The Public Utilities Board

REPORT
# of the
PUBLIC UTILITIES BOARD

in respect of

MAJOR CAPITAL PROJECTS
of
MANITOBA HYDRO

VOL. I

November, 1990

Manitoba

**Cooperative, Consumer
and Corporate Affairs**

The Public Utilities Board

2nd Floor
280 Smith Street
Winnipeg, Manitoba, CANADA
R3C 1K2

(204) 945-2638
FAX: (204) 945-2643

November 30, 1990

Hon. Gary Filmon,
Premier,
Province of Manitoba,
Room 204,
Legislative Building,
Winnipeg, Manitoba.
R3C 0V8

Dear Mr. Filmon:

Re: **The Public Utilities Board Review of Manitoba Hydro's Major Capital Projects for the Period 1990 to 2009**

Pursuant to Order-in-Council 177/90 and 1119/90 and Section 107 of The Public Utilities Board Act the members of The Public Utilities Board hereby transmit to you its Report on its findings following public hearings to consider Manitoba Hydro's proposals in respect of major capital projects required for generation and transmission during the period 1990 to 2009.

Sincerely,

E. J. Robertson, Chairman

W. T. Laird

W. T. Laird, Member

Catherine Milner

Catherine Milner, Member

Debra Barrett-Hrominchuk, Member

T. D. Bulloch, Member

92-07575/

Manitoba Hydro

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Executive Summary

Pursuant to Order in Council No. 177/90, The Public Utilities Board (the "Board") conducted a review of Manitoba Hydro's proposals in respect of major capital projects required for generation and transmission during the period 1990 to 2009, with emphasis on those facilities required by the year 2000.

The public hearings were held in Winnipeg, Manitoba at the Holiday Inn - Downtown on August 20 - 24, August 27 - 31 and September 4 - 6, 1990; at the Hotel Fort Garry on September 7 - 8, 1990; and at the Viscount Gort Flag Inn from October 10 - 13, 1990. Public meetings were also held for presenters in Thompson, Manitoba on September 10 - 11, 1990.

The public hearing process that was undertaken was consistent with the hearing process followed by the Board in regulatory matters. Interested parties were allowed to review Manitoba Hydro's submission documents and actively participate in the hearing process as intervenors. Other interested parties who did not want to participate fully in the hearing process were permitted an opportunity to make presentations at the hearing.

The Board views the proposed hydraulic development in Northern Manitoba in the context of long term planning commitments and investment decisions made by Manitoba Hydro and Provincial Governments during the 1960's and the 1970's.

During that era, the Province of Manitoba decided that its future power needs should come mainly from its northern hydro-electric resources and the Province began a systematic development of the major rivers. Manitoba Hydro has now proposed a number of alternative scenarios, all of which seek to continue the development of the Nelson-Churchill River system.

In the course of its review, the Board considered projections of load growth which indicate that under Manitoba's planning criteria, new sources of generation will be needed to provide for Manitoba's needs in the early years of the next century. The Board finds that the criteria are appropriate and accepts the load forecast for the purpose of generation planning.

The lead time required for development of a major hydro-electric station is in the order of ten years. It is therefore apparent to the Board that in the absence of an early decision regarding the next capacity addition, Manitoba's future options will be substantially restricted.

The Board is of the opinion that in its review, all reasonable sources of supply and means of reducing demand were considered. These potential supply and demand side resources were combined in various ways to form development scenarios. Manitoba Hydro put forward seven scenarios, and a number of others were proposed by intervenors.

Of the seven Manitoba Hydro scenarios, the one advocated by Manitoba Hydro as its Preferred Development Plan consisted of four principal initiatives; sale of 1000 MW and associated energy to Ontario Hydro; Diversity Agreements totalling 300 MW with Northern States Power and United Power Association; a program to maintain existing thermal plants in service until 2000; and a demand-side management program to save 100 MW of demand and associated energy by 2001. The Preferred Development Plan would require construction of the Conawapa generating station, Bipole III to bring the additional power to Southern Manitoba, an AC transmission line to the Ontario border, and greater transmission capacity to the U.S. border.

Intervenors argued that The Manitoba Hydro Act does not give Manitoba Hydro the authority to add system capacity for the purpose of export sales. The Board notes that the service life of Conawapa will approach 100 years, and that a portion of its output will be used to support commitments to Ontario Hydro until the output is more fully required to serve domestic loads. The Board concludes that Conawapa will not be built specifically for export, but rather that the Ontario Sale provides a means of constructing Conawapa without imposing high costs of surplus capacity on domestic customers.

The Board does not consider that interpretation of The Manitoba Hydro Act and The Manitoba Energy Authority Act falls within its jurisdiction.

The second Manitoba Hydro scenario of particular relevance omitted the Ontario Sale but included the other initiatives of the Preferred Development Plan. Based on a comparison of net economic benefits of the foregoing plans, the Board finds that the Preferred Development Plan has a substantial advantage; the difference having a present value of $696 million in 1989 expressed in dollars of 1989 purchasing power.

Because the two scenarios differ only with respect to the inclusion or omission of the 1000 MW Ontario Sale, the comparison measures the overall benefits of the Ontario Sale. The Board finds that of the total benefit, about $468 million derives from profits of the Ontario Sale and the balance from indirect benefits related principally to system reliability, marketing of non-firm surplus energy, and other operating advantages.

Scenarios proposed by intervenors were generally designed to avoid the early construction of Conawapa generating station, in one case by deferral of the Ontario Sale and in others by omission of the Sale, greater reliance on demand-side initiatives and use of less conservative planning assumptions.

Based on comparisons of net economic benefit, reliability and risk, the Board concludes that the Preferred Development Plan proposed by Manitoba Hydro is the least cost option; that it would result in lower customer rates from 1996 to at least 2027; that it provides the highest level of reliability and the lowest ratio of risk to benefits.

The environmental aspects of the Manitoba Hydro Preferred Development Plan will be the subject of hearings before the Clean Environment Commission and are not within the scope of the Board's review. However, in its comparison of scenarios, the Board considered risks due to possible project modifications required to meet environmental requirements and finds that all the scenarios examined involve risk of this nature.

As a result of its review, the Board therefore endorses those features of the Manitoba Hydro Preferred Development Plan requiring early commitment; specifically the system participation agreement with Ontario Hydro, construction of Conawapa generation station and Bipole III, diversity agreements with NSP and UPA, DSM initiatives and thermal plant life assurance.

The Board has not evaluated elements of the Manitoba Hydro Preferred Development Plan scheduled for later years, concluding that they can better be assessed in future reviews.

Many other issues were discussed during the hearing including environmental costs, socio-economic costs, demand side management, load forecasting techniques, diversity exchanges, thermal life assurance, mitigation issues and rate issues. Several of these issues merit ongoing attention and periodic review. However, these issues do not individually or collectively affect the major conclusions of the Board relative to the approval of the Ontario Sale and endorsement of Conawapa as the appropriate next generation facility.

The Board's specific findings and recommendations are set out in Section 16.

Introduction

Purpose of the Hearing

The Manitoba Hydro-Electric Board (Manitoba Hydro) requested the Government of Manitoba to order a public review of Manitoba Hydro's proposals in respect of major capital projects required for generation and transmission during the period 1990 to 2009.

During the public hearing Mr. Ransom, Chairman of Manitoba Hydro, stated:

> "Manitoba Hydro's long-term capital planning has, for the past 25 years, been amongst the foremost questions of public policy in this province and has been the subject of much political debate and one judicial inquiry. There has been very little opportunity for informed debate prior to major commitments being undertaken. Manitoba Hydro recognizes that it is in the public interest to have an open, objective, and public review of our major capital plans before final commitments are made. We are, after all, proposing to invest over $6 billion in the preferred sequence over the next 10 years. Accordingly, Manitoba Hydro has requested that the Government of Manitoba empower the Public Utilities Board to review our long-term capital plans."

(Transcript, Volume 1, Page 71)

On February 14, 1990, Order in Council No. 177/90 was approved, wherein the Minister of Cooperative, Consumer and Corporate Affairs recommended that the Public Utilities Board (the Board) be assigned the duty of reviewing, at a public hearing, Manitoba Hydro's proposals in respect of major capital projects required for generation and transmission during the period 1990 to 2009, with emphasis on those facilities required by the year 2000. A copy of Order in Council No. 177/90 is included in Appendix I to this report.

The Order in Council requires the Board's review to include consideration of:

1) The recent agreements signed between Manitoba Hydro and Ontario Hydro to supply Ontario Hydro with a firm supply of power starting in the year 2000.

2) The agreements signed between Manitoba Hydro and Northern States Power and United Power Association for diversity exchanges commencing in 1995.

3) The effect of the proposed capital projects on the electricity rates to be charged to Manitoba consumers and the methods proposed to phase in these effects, particularly in regard to the construction of Conawapa and its associated transmission lines.

4) The necessity of the proposed major capital projects, their physical and engineering characteristics and their economic consequences with emphasis on:

    a) Load forecasts and forecasting methods used, as well as an indication of the relative success of previous forecasts.

b) A description of the process to be used by Manitoba Hydro in the development and implementation of its demand-side management programs.

c) Evidence that all reasonable alternative options have been considered and that the proposed capital projects have been selected on reasonable grounds i.e. technical feasibility, cost efficiency, and reliability.

d) The analysis by Manitoba Hydro of potential risks from all causes - including economic, financial, and technical risks. By reason of the fact that these same capital projects will be the subject of hearings before the Clean Environment Commission, analysis of risks should include possible modifications to the capital projects resulting from the environmental review.

Public Hearing Process

The public hearing process that was undertaken by the Board was consistent with the hearing process followed by the Board in regulatory matters. (see Appendix II for general information on the Hearing Process and the Regulatory Process)

A preliminary notice, dated February 28, 1990, was published in daily and weekly newspapers throughout the Province and served on interested parties. A technical conference was held at the Hotel Fort Garry on Monday, April 30, 1990, and a pre-hearing conference was held on May 7, 1990. A further notice, dated May 29, 1990, was published in daily and weekly newspapers throughout the Province and served on interested parties.

Interested parties were allowed to review Manitoba Hydro's Submission (Exhibit #MH-2A) and if an interested party wished to take a position in respect of Manitoba Hydro's Submission, an application to become an "Intervenor" was submitted to the Board. In this public hearing the following interested parties were granted intervenor status, and are referred to in this report, as they were at the hearing, by the acronym following their name:

a) Consumers Association of Canada (Manitoba)/Manitoba Society of Seniors (CAC/MSOS).

b) Concerned Citizens of Manitoba Inc./Sierra Club of Western Canada, Manitoba Branch/Conservation Strategy Association of Manitoba Inc. (CSC).

c) Manitoba Industrial Power Users Group (MIPUG).

d) Northern Flood Committee (NFC).

e) Community Association of South Indian Lake Inc. (SIL).

f) Manitoba Keewatinowi Okimakanak, Inc. (MKO).

If an interested party did not want to take an active role as an intervenor but wanted to make a statement to the Board concerning Manitoba Hydro's Submission, they were invited to appear as a "presenter".

Two independent witnesses, not affiliated with any of the intervenors, were engaged to provide their input in respect of Manitoba Hydro's Submission. The independent witnesses were George W. Clayton P. Eng. (GWC) of Vancouver, B.C. and Whitfield Russell Associates (WRA) of Washington, D.C.

A detailed list of the appearances at the hearing, including the Manitoba Hydro panel, intervenors, presenters, and independent witnesses is contained in Appendix III.

Prior to the hearing, the intervenors and independent witnesses asked questions of Manitoba Hydro, in writing, and were given written responses. Manitoba Hydro similarly was allowed to ask questions, in writing, of the intervenors and independent witnesses. The intervenors and independent witnesses filed written testimony in advance of the hearing. Manitoba Hydro then filed written rebuttal evidence addressing some of the issues raised by the intervenors and independent witnesses.

At the actual public hearing, a panel of Manitoba Hydro witnesses provided sworn oral testimony in respect of Manitoba Hydro's submission. The intervenors and the Board, through their respective counsel, cross-examined Manitoba Hydro's witnesses.

The witnesses for the intervenors and the independent witnesses also provided sworn oral testimony at the hearing and were subject to cross-examination by counsel for other intervening parties, Manitoba Hydro and the Board.

The public hearing was held in Winnipeg, Manitoba at the Holiday Inn - Downtown on August 20-24, August 27-31, and September 4-6, 1990; at the Hotel Fort Garry on September 7-8, 1990; and at the Viscount Gort Flag Inn from October 10-13, 1990.

A public meeting, to hear presenters, was held in Thompson, Manitoba at the Royal Canadian Legion, Burntwood Branch, on September 10 and 11, 1990.

At the conclusion of the public hearing, Manitoba Hydro filed its written argument with the Board on October 19, 1990. The intervenors and Board counsel filed their written arguments with the Board by October 24, 1990.

The Board then heard oral argument from Manitoba Hydro, the intervenors and Board counsel on October 29 and October 30, 1990 at the Board's office in Winnipeg.

The report by the Board is to be forwarded to the Lieutenant Governor in Council not later than November 30, 1990 (see Order in Council No. 1119/90, in Appendix I). This report is pursuant to that requirement.

A Glossary of Electrical Terms is provided in Appendix IV.

Report Structure

This report has been divided into sections dealing with major aspects of Manitoba Hydro's submission, starting with an overview and background of Hydro-Electric Development in Manitoba. The report then reviews Manitoba Hydro's Role and the Present System, relying primarily on the non-controversial evidence provided by Manitoba Hydro. The remaining sections of the report addresses more controversial aspects of Manitoba Hydro's Submission and examines the position taken by Manitoba Hydro and the positions taken by various intervenors and independent witnesses. Where the Board has made certain findings based on the evidence adduced during this public hearing review process, those findings are at the conclusion of each section.

The totality of the Board Findings, as compiled from the various sections, will comprise the final section of this report, which is the Board Findings and Recommendations in respect of Manitoba Hydro's proposed Major Capital Projects required for generation and transmission during the period 1990 to 2009, with emphasis on those facilities required by the year 2010.

Hydro-Electric Development in Manitoba

The Electric Power Industry in Manitoba

The history of the electric power industry in Manitoba began over a century ago during the pioneer days of street lighting and street railway transportation in Winnipeg. Over the years, a series of amalgamations, purchases and government appointed bodies followed. By the 1940s, the various companies and municipal utilities evolved into three major electrical utilities: Winnipeg Electric Company, City of Winnipeg Hydro Electric System (City Hydro) and Manitoba Power Commission.

By the end of World War II, it became evident that Manitoba's future power requirements would be best served by a single utility responsible for developing and supplying electrical energy. The end result of that decision was the formation of The Manitoba Hydro-Electric Board in 1949 by the Manitoba Government.

In the following decade, Manitoba's distribution and generation facilities were consolidated. In 1952, the government authorized The Manitoba Hydro-Electric Board to acquire the Winnipeg Electric Company. In 1955, all distribution properties in the suburbs owned by City Hydro were sold to the Manitoba Power Commission. In addition, all distribution properties in the City of Winnipeg owned by the former Winnipeg Electric Company were sold to City (Winnipeg) Hydro.

By 1961, the Manitoba Government decided to unite the two provincial utilities. The Manitoba Hydro Act was subsequently passed by Legislature on April 1, 1961, providing for the amalgamation of the Manitoba Power Commission and The Manitoba Hydro-Electric Board into a single crown agency to supply the future energy needs of the province.

In 1973, the last of the small, independent electrical systems joined Manitoba Hydro. Since then, Manitoba Hydro has continued its efforts to strengthen reliability, expand interconnections and keep abreast of electrical technology.

Today, Manitoba Hydro distributes electricity throughout the province except for the central portion of the City of Winnipeg which is served by city-owned Winnipeg Hydro. The affairs of the Corporation are governed by a Board of 10 members appointed by the provincial Cabinet. Through its Chairman, the Board reports on the activities of Manitoba Hydro to the Minister responsible for the administration of the Manitoba Hydro Act who, in turn, reports to the Legislative Assembly. In this manner, Manitoba Hydro is responsible to the people of Manitoba through their elected representatives.

Hydro-Electric Development in Manitoba

In 1913, the Canadian Department of Mines conducted a comprehensive geological survey of the Nelson and Churchill River basins to determine the energy potential of Manitoba's northern river systems. However, this energy potential could not be developed until the 1960's when advances in High Voltage Direct Current (HVDC) technology made it feasible to transmit electrical energy over extremely long distances.

Up until the 1960s, Manitoba's energy requirements were met by six power plants on the Winnipeg River in the southern half of the province. In 1960, the first major northern generating station, Kelsey, was completed on the upper Nelson River. Kelsey was built to supply power to INCO Ltd.'s mining and smelting operations at nearby Thompson. In 1966, Manitoba Hydro adopted a long-range plan to develop additional stations on the northern river system. This launched a decade of hydro construction which created significant provincial economic growth. Kettle, Long Spruce and Jenpeg, all Nelson River plants, were completed in the 1970s.

With the start of the Nelson River development, Manitoba Hydro also began building HVDC lines so that electricity from the new plants could be economically transmitted to major load centres in southern Manitoba.

The pre-filed testimony of C.F. Osler, on behalf of the Manitoba Industrial Power Users Group, summarized the historical context of the Nelson River development as follows:

> "The Nelson River power development program commenced in the mid-1960's. Given the need for new power capacity, it was noted that additional hydro-electric sites no longer existed in Southern Manitoba. Nuclear power was not suited, at that time, to the Manitoba system. In addition, comprehensive economic analysis indicated that long-term coal thermal expansion would be slightly less desirable than hydro-electric expansion along the Nelson River. On this basis, it was decided that Manitoba's future power needs up to the end of this century could probably best be met by a comprehensive development of the capacity on the Nelson River. The initial phase of development announced in 1966 included four items: a major power site at Kettle Rapids; an HVDC transmission line from Kettle to southern Manitoba (this element involved extensive federal government assistance through lease of facilities at highly favourable terms); a diversion of the Churchill River at Southern Indian Lake into the Burntwood and Nelson Rivers; and a control structure to regulate water levels on Lake Winnipeg with the aim of better controlling Nelson River seasonal flows."

(MIPUG, Pre-filed Testimony, pages 2-3)

By the mid-70's, the northern hydro-electric system was in place. However, a slow-down in domestic load growth in the late 1970s forced the postponement of further construction on the Nelson River, with 70% of the generating potential still untapped. Construction of the Limestone Generating Station was suspended in the preliminary stages until the early 1980's when North American utilities - concerned about the escalating costs of various forms of energy - started negotiations for major long-term power sales with Manitoba Hydro.

In the Chairman's Message contained in Manitoba Hydro's 1981 Annual Report, Kris Kristjanson, then Chairman of Manitoba Hydro, had the following comments about the development of hydro-electric energy in Manitoba:

> "Currently, hydro-electric energy accounts for about 96.9% of the electrical energy made available in the province, and 74.5% of the total originates from the Nelson-Churchill River System. With the inflationary trend in recent years multiplying the costs of nonrenewable fuels and transportation, it now becomes more obvious that the decision made in the early sixties to develop the Nelson-Churchill River System, instead of thermal plants, was a very wise decision. About one-third of the potential has been developed to date and the remaining two-thirds will be developed in a prudent manner in accordance with the basic intent of The Manitoba Hydro Act."

In 1984, Northern States Power Company of Minneapolis agreed to purchase 500 megawatts of power over a 12-year period starting in 1993. This contract paved the way for Manitoba Hydro to resume construction of the Limestone plant.

In the Chairperson's Message contained in Manitoba Hydro's 1985 Annual Report, Marc Eliesen, then Chairperson of Manitoba Hydro, summarized the current developments in Manitoba Hydro's northern development program:

> "In June of 1984, Manitoba Hydro together with the Manitoba Energy Authority, signed a contract for the sale of 500 megawatts of power to the Northern States Power Company of Minneapolis, for a 12-year period, beginning in 1993. The National Energy Board (N.E.B.) has approved the sale which is expected to produce revenues of $3.2 billion. Of this amount, about $1.7 billion is estimated to be profit that will be used in part to maintain Manitoba Hydro's rate structure below that of nearly every other utility in North America.
>
> The N.E.B. approval also provided the catalyst for the startup of construction on the Limestone Generating Station. In addition to the profits that will accrue from expanded export sales, economic benefits will flow from the construction program, stimulating business activity and creating thousands of jobs for Manitobans.
>
> Manitoba Hydro will work with government and community representatives to fulfill social, economic and environmental goals relating to major construction programs such as Limestone. The focus will be on maximum northern involvement."

During 1986, Manitoba Hydro concluded a 200 megawatt power sale to Northern States Power Company, starting in 1993 and continuing to 1996. Negotiations towards further power exports were underway with Ontario Hydro and a number of U.S. utilities, including The Upper Mississippi Power Group (UMPG) which is a group of utilities from Minnesota, Wisconsin and Iowa, and the WISMINTOBA Group, which is a group of utilities from eastern Wisconsin, Upper Michigan and Minnesota. Manitoba Hydro also completed a study on the transmission of power to the Western Area Power Administration (WAPA) which is based in Colorado and distributes power throughout the central and western U.S.

In Manitoba Hydro's 1986 Annual Report, the influence of recent export contracts and negotiations on corporate strategy was reported as follows:

> "Recent export contracts - plus current negotiations with a number of Canadian and U.S. utilities wanting Manitoba's power - have led to a decision to resume hydro-electric development on the Nelson River. Since two-thirds of the Nelson's clean, renewable energy potential still remain untapped, this decision will have a major beneficial impact on Manitoba's economic well-being in both the short and long term.
>
> Corporate purchases and employment have already increased as a result of the 1985 start of construction on the $1.94 billion Limestone Generating Station on the Nelson. But while export contracts generate plenty of excitement and activity, Manitoba Hydro has not lost sight of its mandate to provide Manitobans with electricity at reasonable prices."

The 1986 Annual Report also noted that an abundant supply of renewable energy would give Manitoba a competitive advantage:

> "Abundant supplies of renewable energy at reasonable prices will give the province a competitive advantage in attracting new industry in coming decades. The objective of the provincial government is to seek stable and steady growth, building on Manitoba's traditional strengths and realizing new opportunities. Because of the lure of attractive electricity rates, the province in future could become the profitable home of many more energy-intensive industries. In particular, there will be competitive advantages here for companies that produce such products as hydrogen, glass, silicon, plasma, optical fibres, ceramics and chemicals."

During 1987, the Manitoba Energy Authority, in conjunction with Manitoba Hydro, continued negotiations with a number of interested groups for the sale of electricity. In February 1987, Manitoba Hydro signed an agreement with Minnesota Power & Light Company for a seasonal exchange of 50 megawatts of power, the power being exported from Manitoba in the summer of 1987 and returned in the winter of 1989. Negotiations continued on a power sale and diversity exchange with U.S. Utilities from Minnesota, Wisconsin and Iowa known as the Upper Mississippi Power Group. In addition, discussions continued with Ontario Hydro on the possibility of power sales ranging from 200 megawatts to 1,000 megawatts starting in the late 1990s.

During 1988, employment levels peaked at the Limestone Generating Station then in its fourth year of construction. Activity shifted from major civil construction to the installation of electrical and mechanical components. Other system developments included the completion of a major new transmission line to Churchill.

In 1989, Manitoba Hydro introduced an electricity supply plan intended to meet the electricity needs of Manitobans into the 21st century. The four initiatives under the plan, now referred to as the Manitoba Hydro Preferred Development Plan, are as follows:

1) 1,000 megawatt sale to Ontario Hydro for 22 years, starting in the year 2000.

2) 150 megawatt diversity exchange agreements with Northern States Power Company of Minneapolis and with United Power Association of Elk River, Minnesota, beginning in 1995.

3) A 100 megawatt target reduction in load forecast through demand-side management by 2001. The Corporation intends to encourage Manitoba consumers to reduce their energy consumption in order to defer the next new generation source by at least one year.

4) Rehabilitation work on the Brandon and Selkirk thermal generating stations. Thermal life assurance will ensure that the plants will last until their predicted retirement dates and thereby defer the need for replacement generation.

On December 7, 1989, Manitoba Premier Gary Filmon and David Peterson, then Premier of Ontario, signed agreements for the sale of 1,000 megawatts of firm power to Ontario Hydro for 22 years, starting in the year 2000.

Mr. Ransom summarized the rationale behind Manitoba Hydro's Preferred Development Plan:

> "At the time that I became Chairman of Manitoba Hydro in June of 1988, the then-current integrated financial forecast projected Conawapa as being the most economic means of meeting Manitoba load and firm export commitments when a new source of generation would be required in 1999. Although Wuskwatim was still an option, appropriate levels of environmental studies were not underway to maintain Wuskwatim as a practical alternative to Conawapa.
>
> Therefore, in late 1988, additional effort was directed towards intensifying environmental studies aimed at restoring Wuskwatim as a practical alternative to Conawapa for 1999. This was judged particularly prudent because the Upper Mississippi Power Group had dropped out of negotiations for a purchase of 400 megawatts of firm power, which would have confirmed construction of Conawapa and helped to carry its costs. The withdrawal of the Upper Mississippi Power Group from negotiations for firm power led, over the next few months, to interest by United Power Associates and Northern States Power in a 300-megawatt diversity exchange. Towards the end of 1988, Ontario Hydro expressed active interest in a 1,000 megawatt purchase of firm power.
>
> At this point, thermal life assurance was not a certainty and the Hydro Board was acutely aware that Hydro would, in all probability, have to build either

Conawapa or Wuskwatim by 1999, with all the costs and risks to be borne by Manitoba consumers unless export sales could be negotiated.

A decision was made to vigorously pursue the Ontario Sale with one overriding constraint; Manitoba consumers had to be better off in every year of the sale than would otherwise be the case, and I should add that Hydro engaged an outside consultant at this point to advise whether or not our proposed sale to Ontario was prudent and reasonable. The decision was made to pursue the diversity exchange because that would provide some flexibility and assure adequate energy in the critical period before the next generating station came into service.

Concurrently, during the spring and summer of 1989, the Board of Manitoba Hydro began developing policies designed to engage demand-side management and non-utility generation. One result of this initiative was the Board's setting in September, 1989 of a 100 megawatt minimum demand-side management target for 2001 with the objective of delaying the next plant after Conawapa or Wuskwatim. We judged it to be prudent and reasonable to concentrate these excursions into unproven programs in the period after the building of our next plant.

By October, 1989, neither the Ontario Sale nor the diversity agreements were yet assured, nor was thermal life assurance yet a certainty. Decisions for supply to meet the 1999 load growth became more pressing. We therefore intensified our efforts to conclude the diversity agreements, which were ultimately signed November 21, to the considerable relief of all of us who were closely involved. The Ontario agreement was signed December 7th.

A review of Hydro's major capital plans as presented has led some intervenors to conclude that Conawapa is being advanced to accomodate the Ontario Sale. Mr. Chairman, I think it is relevant for me to state that from the perspective of the Manitoba Energy Authority and the Hydro Board, our package of initiatives delayed the construction of a major plant, Conawapa or Wuskwatim, by one year, and assured that Manitoba customers would not bear the cost of the next source of generation by themselves. The one-year delay has also allowed more time for our current review and for a more thorough environmental review than if we were attempting to meet the 1999 in-service date.

Our change of policy to value energy conserved or purchased at avoided cost has set Manitoba Hydro on a course that will significantly alter our future plans, especially in the period after the year 2000. In our judgement, these decisions reflect changing public attitudes towards energy and our environment while still being prudent and reasonable in assuring an adequate supply of electricity.

In summary, Mr. Chairman, this package of initiatives was driven primarily by an interest for Manitoba consumers of electricity. The Ontario Sale, in particular, was required to meet the rigid constraint that Manitoba consumers had to be better off in every year of the sale than would otherwise be the case. I believe

> that the interests of our consumers have been protected and that the preferred development plan before you is prudent and reasonable and will fulfill the mandate of the Manitoba Hydro Act."

(Transcript, Volume 1, pages 74-77)

Appendix V briefly highlights the historical development of hydro-electricity in Manitoba.

The Board notes that Manitoba Hydro's proposed generation expansion sequences are consistent with past decisions and commitments made to develop Manitoba's northern river systems. Manitoba Hydro's proposed alternatives, examined in the hearing, seek to continue the development of the Nelson-Churchill River system. The Board also notes that one of Manitoba Hydro's strategic objectives is to secure beneficial export agreements as evidenced by the agreements listed in Appendix VI.

Manitoba Hydro's Role

Manitoba Hydro Act

The Manitoba Hydro Act, provides for the creation and operation of Manitoba Hydro in Section 2:

> "The intent, purpose and object of this Act is to provide for the continuance of a supply of power adequate for the needs of the province, and to promote economy and efficiency in the generation, distribution, supply, and use of power."

Manitoba Hydro has testified that it considers this statement to be its mandate.

Manitoba Hydro's Goals

Manitoba Hydro had previously developed nine Strategic Objectives which collectively define its goals in more detail. (see Perspective 2000, in Appendix III of Manitoba Hydro's Submission). Although all of the objectives are ranked equally, the majority of activities are directed at achieving the first objective of supplying electric power. The other objectives tend to define the conditions surrounding, influencing and tempering these activities.

Manitoba Hydro contends its planned program will achieve its mandate while simultaneously addressing all its Strategic Objectives, which are listed as follows:

1) To provide a safe, adequate, economical and reliable supply of electricity to meet customer requirements.

2) To provide all customers with excellent service with particular focus on individual customer satisfaction.

3) To promote conservation of electricity when it can be achieved more economically than supply.

   The promotion of conservation, through programs known as Demand-Side Management, generally involves encouraging customers (either through information or incentives) to modify their energy consumption without negatively impacting on their lifestyle, benefits or conservation. Manitoba Hydro implements such programs with an additional objective of lowering the total revenue requirement of the utility.

   Manitoba Hydro has stated that it practises Least Cost Planning by selecting the combination of facilities, import/export arrangements and resource management programs that contribute to the lowest rates and lowest long-term costs for electricity supply. Manitoba Hydro also considers Least Cost Planning to include the consideration of potential investments to modify customer requirements. Manitoba

Hydro plans to incorporate investments in electricity conservation where this can be achieved at less than the avoided cost of supplying that electricity.

4) To develop and maintain a workforce with a high level of motivation, productivity and job satisfaction.

5) To improve productivity and quality in all segments of the business on a continuing basis.

6) To be recognized as a good corporate citizen which deals sensitively and fairly with the effects of its activities on communities and individuals.

In order to ensure that its development activities are environmentally acceptable, Manitoba Hydro has stated that it will:

a) Prevent predictable and unacceptable adverse environmental effects.

b) Develop plans for reducing expected but unavoidable adverse effects.

c) Ensure that all potentially affected individuals, groups, and organizations are given the opportunity to provide substantive input to decisions.

d) Identify and correct environmental problems in a timely and effective fashion.

e) Ensure that all adversely affected parties are dealt with fairly and equitably.

f) Assist people in adjusting to development impacts.

g) Comply with relevant environmental laws, regulations, and government policies.

7) To conduct all corporate activities in accordance with the principles of sustainable development.

Manitoba Hydro's sustainable development activities include the following:

a) The promotion of the economic conservation of energy to ensure that electricity requirements increase at a slower rate than they would without this intervention.

b) The operation of hydro-electric generating stations to avoid consuming non-renewable resources and to avoid the consumptive use of a renewable resource.

c) The planning of hydro-electric plants as an environmentally preferable alternative to other methods of generation such as coal-burning plants.

d) The sale of electricity into Ontario, Minnesota, North Dakota and Saskatchewan to allow the purchasing utilities to reduce their consumption of non-renewable fossil fuels.

e) The planned projects are expected to contribute to economic development in Manitoba through:

   i) the employment/procurement activities involved in constructing and operating the facilities and conservation programs, and

   ii) the maintenance of relatively low electricity prices.

8) To assure the Corporation's long-term financial integrity.

Operations for the year ended March 31, 1990 resulted in a net income of $24.2 million compared to a net loss of $26.4 million in the previous fiscal year. The improvement of $50.6 million in operations is primarily attributable to the financial impact of improved water flow conditions during the first part of the fiscal year and to the average general consumer rate increase of 5.0% implemented April 1, 1989.

Although Corporate financial reserves increased from $92.4 million in 1988-89 to $116.6 million in 1989-90, they remain significantly lower than the current targeted minimum reserve level of approximately $210 million. The debt/equity ratio, at 97:03, is the second weakest of all publicly-owned electric utilities in Canada. Manitoba Hydro's goal is to build reserves to adequate levels in order to prevent large rate increases caused by periodic droughts and unexpected contingencies and to avoid large rate fluctuations when major new facilities are added to the system.

(Manitoba Hydro, 1990 Annual Report)

9) To secure beneficial extra-provincial agreements.

A listing of Manitoba Hydro's export agreements is included in Appendix VI.

Position of Independent Witnesses and Intervenors

In both of their respective opening remarks, counsel for CAC/MSOS and CSC advanced the position that Manitoba Hydro's proposed construction of new dams and transmission lines was entirely for export rather than for Manitoba consumers' needs and was outside the lawful mandate of Manitoba Hydro.

CAC/MSOS elaborated on this position, at some length, in its final argument, as did CSC.

Manitoba Hydro addressed this issue and responded to the intervenors' concerns in its closing argument. Manitoba Hydro took the position that The Manitoba Hydro Act and The Manitoba Energy Authority Act provide sufficient statutory powers to permit Manitoba Hydro to embark on its Preferred Development Plan including the proposed sale to Ontario Hydro.

Board Findings

The Board is of the view that it does not have jurisdiction to decide a dispute on the interpretations to be given to The Manitoba Hydro Act or The Manitoba Energy Authority Act.

Any concerns or disputes over the interpretation of such legislation should be resolved in a proper forum, which may be the courts as suggested by Manitoba Hydro, or amongst the Government, the Legislature and Manitoba Hydro as suggested by MIPUG.

Having noted the above, the Board does not, as the body of this report will make clear, consider that Manitoba Hydro proposes in any of its scenarios to construct generation facilities solely for export sales.

The Present System

This section was derived in large part from section 2 of Manitoba Hydro's Submission.

Manitoba Hydro operates an integrated system which supplies Manitoba from thirteen hydro plants and two thermal plants. The major transmission system includes two high-voltage direct current (HVDC) transmission lines, called Bipole I and Bipole II, which connect northern generating stations on the Nelson River to southern load. Bulk transmission throughout the rest of the province consists of a network of alternating current (AC) lines of various voltages.

The transmission system is interconnected by tie lines with a combined nominal capacity of 1,850 megawatts (MW) to utilities in neighbouring provinces and in the United States. Appendix VII shows the generation and major transmission in the present integrated system.

Generation Capacity

The total installed capacity of the existing hydro plants is 3,548 MW (excluding Limestone) and the two thermal plants have a total capacity of 369 MW. The useful life of a hydro stations is approximately 100 years and no plant retirements are currently scheduled. The useful life of a coal-fired plant ranges from 30 to 40 years, and both thermal plants are of this vintage. They currently have anticipated retirement dates as shown below:

Current Anticipated Retirement of Thermal Plants

Name/Unit	Rating MW	Commissioned	Retirement Date
Brandon 1-4	132	1957-1958	Mar. 2000
Brandon 5	105	1969	Mar. 2006
Selkirk 1-2	132	1960-1961	Mar. 2005

It is noted that the Amy Street 1-3 thermal units were commissioned from 1924-1954 and provided 35 MW of capacity until they were retired in June 1990.

Manitoba's supply is augmented by seasonal diversity agreements with Northern States Power (NSP) and United Power Association (UPA) which provides 300 MW of winter capacity until 1993. By 1992, after the 1,330 MW Limestone Generating Station is completed, the system capability will be approximately 5,500 MW as follows:

System Operating Capacity - 1992
At Point of Generation (or Equivalent)

Source of Capacity	**Capacity MW**
Winnipeg River (6 generating stations)	560
Grand Rapids	440
Jenpeg	102
Kelsey	216
Laurie River (2 generating stations)	10
Kettle	1,200
Long Spruce	970
Limestone	1,330
TOTAL HYDRO CAPACITY	4,828
Brandon and Selkirk Thermal	369
NSP/UPA Diversity (300 MW + 10%)	330
SYSTEM CAPACITY	5,527

A new 200 MW diversity exchange with NSP will start in 1996 and last for 20 years.

Energy Generation

Energy capability of hydraulic generation varies with river flow conditions. Dependable energy is plant capability with a recurrence of the lowest historic flows. Under average and high water flow conditions, plants can produce additional energy. In addition to the hydraulic capability, thermal plants at Brandon and Selkirk and agreements with neighbouring utilities provide non-hydraulic capability. By 1992, following completion of Limestone, the annual dependable energy capability in gigawatt hours (GW.h) will be as shown:

Annual Dependable Energy Capability

Source of Energy	Energy GW.h
Winnipeg River (6 generating stations)	2,550
Grand Rapids	1,845
Jenpeg	690
Kelsey	1,745
Laurie River (2 generating stations)	40
Kettle	5,420
Long Spruce	4,440
Limestone	5,850
TOTAL HYDRO DEPENDABLE ENERGY	22,600
Brandon and Selkirk Thermal	1,865
NSP diversity energy guarantee	1,575
TOTAL SYSTEM DEPENDABLE ENERGY	26,040

Under more favourable water conditions, extra hydraulic energy is generated which reduces thermal or import requirements. If surplus is available, it is exported to neighbouring utilities. The variation in hydraulic plant capability with flow is shown below:

Variation in Hydraulic Plant Capability

Flow Condition	Energy GW.h
Dependable	22,600
Average	28,900 (+28%)
High	35,500 (+57%)

Transmission and Distribution

Transmission line distances for the major voltage levels as of 1989 are as follows:

Transmission Line Distances in Manitoba

Voltage	Total Line Length km
500 kV AC	209
+/-500 kV DC	1,833
230 kV AC	4,276
138 kV AC	951
115 kV AC	3,023

Power from generation and imports is generally received at high voltages ranging between 115kV and 500kV and is stepped down at transformer stations to subtransmission voltage levels such as 33kV and 66kV for transmittal to large load centres in cities, towns and villages. At these locations, voltage is reduced in distribution stations to distribution voltage level, typically 12kV and 24kV, to serve individual customers, usually industrial, and districts. Finally, the voltage is reduced to the customer utilization level by distribution transformers located on hydro poles or on ground-level pads.

Exports and Imports

Existing interconnections to neighbouring utilities are used to meet committed contracts for export or import of firm power, as well as providing the means to export surpluses on an opportunity basis and import for emergency purposes. Interconnections with utilities much larger than the Manitoba System provide a high degree of security in cases of emergency and also provide opportunities for economic gain. Export opportunities with American or Canadian utilities are negotiated where a clear business case can be made that the export arrangement results in lower rates for Manitoba consumers than they otherwise would be. Appendix VI summarizes the current agreements and their related terms and conditions.

Diversity Sales

Diversity exchanges are a form of agreement between a summer-peaking U.S. utility and a winter-peaking Canadian utility. Canadian utilities export power and energy in the summer from plants that would not be needed to meet domestic requirements, and import in the winter from U.S. plants that would otherwise sit idle. The result is that both utilities can defer new plant, with resultant savings to customers of both utilities.

Surplus Energy Sales

Two factors result in more energy normally being available than is required to meet the Manitoba need.

The first one is due to the fact that when a new hydraulic generating station comes into service, there is surplus capacity. Since much of the construction costs are associated with the-concrete structures, dam and dykes, it is economical to schedule the construction of all the generators in the plant in sequence rather than installing units to follow customer load increases. This creates a temporary surplus of power and energy. This surplus diminishes with time until just before the next plant is commissioned.

The second factor is the dependable flow criterion used for system planning. Water conditions can vary extensively, and in most years, there will be more water available than under low flow conditions, thus resulting in energy surplus to Manitoba Hydro's requirements. Because the amount of this type of surplus energy is unpredictable, it is sold on the condition that it may be curtailed should the energy be required in Manitoba.

The revenue received from surplus energy sales to neighbouring utilities reduces the revenue that would otherwise have to be collected from Manitoba customers.

Firm Export Commitments

In a firm export commitment, the exporting utility agrees to supply the importing utility with the specified service for a specified period at a specified price. Importers benefit by deferring new plant construction. Exporters benefit by selling output from a plant that is larger than currently needed for domestic load and using those revenues to offset plant costs.

Current Customers and Consumption

Customers and Consumption

Manitoba Hydro presently serves 372,000 domestic customers, of which 326,000 are residential and 46,000 are general service. Winnipeg Hydro's 90,000 customers are not included in these figures.

Total 1989/90 firm energy generation required to meet all Manitoba customers' requirements was approximately 17,500 GW.h. Peak demand in December 1989 was 3,638 MW. Consumption is much higher in winter due to heating, lighting, and other weather-sensitive demands. The annual load factor (the ratio of average to peak load) is normally about 60%, while daily load factors are normally in the 85-90% range.

Marketing and Conservation Programs

Manitoba Hydro has encouraged energy conservation through consumer information and a general theme of "wise and efficient use of electricity". Efforts of governments and community groups and the support provided by Manitoba Hydro have resulted in energy savings. Although it is impossible to determine accurately what these 'natural conservation' savings have been, Manitoba Hydro estimates that without these conservation efforts, the current consumption levels would be at least 10% higher.

Manitoba Hydro prepares and distributes a variety of publications and print material on conservation, electrical safety and technology interests. The use of energy-efficient appliances as rated through the Energuide Program is also promoted. To support its energy efficiency programs, Manitoba Hydro offers financial assistance in the form of grants and loans.

Other initiatives by the Corporation include working with agencies to improve building codes and to redesign electricity rates.

Non-Utility Generation

The generation of electricity by organizations other than utilities is called non-utility generation (NUG) and can be broadly divided into two categories:

1) Customer-generation occurs when customers generate part of their own electricity requirements. Cogeneration is a desirable form of generation appropriate for customers. It involves a simultaneous generation of electricity and heat.

2) Independent power producers (IPP's) is the term used to cover organizations who are able to generate more than their own requirements and sell the excess to a utility. IPP's may use cogeneration facilities or single-purpose power generation equipment.

While customers' facilities are interconnected to the Manitoba integrated system, they are not considered part of that system. Current estimates are that approximately 60 GW.h is supplied and consumed annually in Manitoba by NUG's as compared to Manitoba Hydro's total hydraulic supply capability of 22,600 GW.h.

Energy and capacity generated through these NUG's is neither estimated as part of the Manitoba firm load nor is it considered as part of the supply capability.

Planning The Future System

This section summarizes section 3 of Manitoba Hydro's Submission.

Planning Criteria and Guidelines

Generation, transmission and distribution planning criteria are a set of rules and guidelines for facilities planners to ensure the development of an economic and reliable supply and delivery system for electric energy. Manitoba Hydro's planning criteria technical staff to carry out studies in a rational and consistent manner, enable managers to make rational decisions, and allow generation, transmission and distribution planning to proceed. These planning criteria and guidelines, particularly as they affect rates, are subject to review and approval by the Public Utilities Board. The following sections summarize the planning criteria and guidelines used by Manitoba Hydro.

Generation Planning Criteria

The capacity reserve criterion and the dependable energy criterion are the two criteria that must be satisfied in planning future generation additions.

Manitoba Hydro's capacity reserve criterion states that a minimum reserve will be carried against breakdown of plant and increases in demand above forecast. This reserve capacity is 12% of the total of the Manitoba forecast peak demand each year, plus those firm export contracts which require a reserve to be maintained, less that portion of the demand provided by firm imports (reserve capacity is provided by the utility providing the firm import).

The dependable energy criterion states that the Corporation will plan to have adequate energy resources to supply the firm energy demand in the event that the lowest recorded coincident river flow conditions are repeated. To meet the firm energy demand, planning studies assume that up to a maximum of 10% of the energy demand in Manitoba can be met from the energy reserves of interconnected utilities, provided an energy purchase contract is or will be in effect during the time being studied.

Transmission and Distribution Planning Criteria

Manitoba Hydro's economic evaluations are used to select the least costly transmission and distribution plan from a number of technically acceptable alternatives.

Manitoba Hydro addresses system reliability by planning for redundancy, alternate supplies, and emergency back-up equipment. In general, the transmission system is designed to a high standard of reliability because a transmission system interruption can affect many customers and can have more severe consequences than the failure of individual generating units and even an entire generating station.

The transmission system is planned for single contingencies. That is, an outage of any network component like a transformer or transmission line must not cause the system to become electrically unstable or cause long-term loss of supply to customers. The simultaneous outage of more than one major transmission line or component can result in customer outages.

Transmission and distribution planning criteria relative to safety are expressed in terms of equipment rating and permissible operating and loading limits. Loading criteria for conductors and transformers are concerned with the effects of excessive heat buildup caused by electric current. Overvoltage criteria define maximum permissible transmission and distribution voltage levels.

Transmission planning criteria for external electrical effects of transmission lines provide limits for radio and TV interference, audible noise, distortion of voltage, telephone interference induced by harmonic currents, electric field effects, and induced voltages in the vicinity of a transmission line.

Manitoba Hydro's other transmission planning criteria pertain to quality of service with respect to frequency and service voltage.

Export/Import Policy

When considering the possible import or export of power, Manitoba Hydro will:

1) Export power and energy which is surplus to Manitoba needs with due recognition of security of supply to Manitoba consumers, and of government policy and regulations.

2) Export or import power and energy to achieve benefits for Manitoba consumers through reduced rates and improved system security.

3) All else being equal, give priority for sale of surplus energy to accessible customers in the following order:

   a) Manitoba consumers.
   b) Canadian utilities.
   c) United States utilities.

4) Export power to neighbouring utilities in time of emergency to the extent such exports will not jeopardize service to customers in Manitoba, and import power from neighbouring utilities in times of emergency to maintain necessary service to consumers in Manitoba.

Financial Targets and Rates Strategy

Short-Term Target:

The first priority is to achieve minimum target reserves equal to the amount required to withstand the financial effects of two years of drought equivalent to the worst on record, plus an amount equal to the maximum single third-party loss for which the Corporation is liable under its self-insurance program.

The objective is to attain the minimum target reserve level as soon as possible within a five-year period, while maintaining a rate strategy sensitive to effects on consumers.

Long-Term Target:

Manitoba Hydro's goal is to move toward a debt/equity target of 85:15 to be achieved within the ten-year period immediately following the attainment of the minimum target reserve level. In moving toward the debt/equity target, the Corporation will aim for an annual gross interest coverage of 1.15 to 1.25 with the understanding that, in the interests of maintaining rate stability, this range may be deviated from immediately prior to and during periods within which the cost of new facilities is being absorbed into the rate base.

In addition to these formal targets which have been approved by the Manitoba Hydro Board, Manitoba Hydro has three interrelated goals:

1) Avoid rate increases in excess of inflation.

2) Minimize rate fluctuations.

3) Maintain positive net income for a majority of years.

It should be noted that Manitoba Hydro's debt/equity targets are used here for planning purposes. While the Public Utilities Board in its Order 43/90 accepted Manitoba Hydro's short-term target, the Corporation's goal of an 85:15 debt/equity target will be the subject of future rate hearings.

Environmental Criteria

Generation and transmission projects must comply with environmental standards set by regulatory authorities. Early in the planning process, judgements are made on the prospect of siting, designing, constructing, and operating projects in compliance with standards of environmental acceptability.

Projects judged to have a low probability of meeting minimum environmental standards or of obtaining public acceptance are screened out. Projects with the potential for achieving regulatory acceptance are evaluated as further information on the nature and extent of the environmental implications is collected. Environmental information is used in making project development decisions and in the ultimate environmental review process necessary for licensing a project.

Sequence Evaluation Methodology

Plans for new generation must be established about ten years in advance of need. This lead time is needed to obtain regulatory approvals, finalize designs, establish infrastructures for plant construction, and construct the facilities. In planning for expansion, however, Manitoba Hydro looks well beyond the ten-year period to ensure that the next generating plant is consistent with the projected long-term needs of the system.

Various combinations of future supply-side and demand-side options are developed to meet the growing needs of the province. Each combination of system expansion to meet a specific scenario is called a 'sequence of development'.

Sequences of development are analyzed using a number of factors in order to determine which is the best sequence to match a specific scenario. Factors considered are:

1) Long-term sequence economics.
2) Socio-economics.
3) Financial implications.
4) Environmental implications.
5) Risks and uncertainties.

When long-term sequences (extending 30 to 40 years into the future) are examined, decisions are made to develop only the next plant and only when required. Longer-term plans are subject to change as better information about the future unfolds. Even the next addition, once 'committed', is subject to continual review as circumstances change.

The following sections discuss each of the factors considered in the analysis of sequences of development.

Long-Term Sequence Economics

Long-term sequence economic evaluations consider the costs and benefits to provide for all future Manitoba load growth, including Winnipeg Hydro. Capital costs include future generation and transmission additions. The operating costs include:

1) Costs to fuel the thermal plants in Manitoba.
2) Costs to import energy.
3) Revenue from extra-provincial sale of surplus energy.
4) Water rental costs.

Evaluations do not include the fixed costs of facilities already in place and incremental cost additions which are common to all alternatives. The costs and revenues for a sequence of development are discounted to a common year with the result commonly called a Net Present Value (NPV). Alternative sequences of development are evaluated by comparing their NPV. The preferred sequence for a specific scenario is the one with the lowest NPV.

Socio-Economics

Socio-economic evaluations are similar to long-term sequence economic evaluations as described above. However, the perspective is broader in that costs and benefits are adjusted to reflect a provincial perspective rather than a utility perspective.

Specifically, labour costs are adjusted downward to take into account the probability that some of the persons hired would otherwise be unemployed. Also, water rentals and provincial sales tax are excluded from the social costs as they represent a government transfer as opposed to a real cost from a provincial perspective.

The costs and revenues for each sequence are then discounted to a common year at the social discount rate. The social discount rate tends to be higher than the discount rate used in the utility analysis since it reflects alternative uses of capital.

Financial and Rate Implications

The effect of alternative sequences on Manitoba Hydro's financial results and revenue requirements is reflected in projected annual operating statements and balance sheets for the period under review. The financial analysis incorporates cost sharing with Winnipeg Hydro, financing considerations, and contributions to reserves in accordance with financial targets.

In ranking sequences from a financial perspective, consideration is given to the timing and size of rate increases. The NPV of cumulative customer revenue requirements over the study period is also compared. Finally, projected borrowing requirements are reviewed and, if sufficiently large, are checked to ensure that they do not exceed the estimated net borrowing capacity of the Province in any year.

Decision Rules for Evaluating Alternative Sequences

In order to compare the preferred development plan to alternative capital plan sequences, Manitoba Hydro priorized its financial objectives as follows:

1) Achieve target minimum reserves by 1994/95.

2) Achieve target 85:15 debt/equity ratio no later than 2004/05.

3) No single year rate increase greater than inflation.

4) No rate reductions (to assist in maintaining rate stability).

5) Equity never less than 13% once 15% equity achieved.

6) Smooth rate increases.

7) No large or multi-year losses.

8) Interest coverage is not to exceed 1.25 except in years immediately prior to in-service of new plant.

Environmental Considerations

The environmental perspective considers the effects of development activities on the physical, biological and aesthetic environment and the related implications on people. No generally accepted approach exists for quantifying or valuing different types of environmental impacts. This restricts the type of environmental evaluation for comparing differing projects and precludes an objective or quantitative ranking of sequences. Manitoba Hydro's environmental evaluation focuses on the likely environmental issues involved with the next plant to be developed. In all plans, this is either Conawapa or Wuskwatim and their related transmission facilities.

Risks and Uncertainties

Risks and uncertainties arise from decisions which must be made to meet expected future conditions. For generation additions, a commitment to the next plant is required about ten years in advance of need. Evaluations are based on expected load forecast, plant costs, value of surplus energy, predicted interest and escalation rates. Evaluations with assumptions changed over a range of plausible different conditions, both higher and lower than the central assumptions, give an understanding of the risks associated with the unpredictability of the assumptions.

Manitoba Hydro's prime objective is to have new facilities in place exactly as required, that is, neither too early nor too late. However, given the uncertainty of events subsequent to the decision to develop a generation site, it is not likely that this objective will be perfectly met.

Interconnections to neighbouring facilities mitigate the impacts of mis-timed generation additions. For facilities which prove to be early, surpluses can be exported; if additions prove to be late, imports can be made.

In general, facilities which are in place too early result in higher costs to Manitoba consumers. Facilities which are too late would also result in higher costs, but could also result in an inability to supply Manitoba load if the deficiencies are large enough.

Position of Independent Witnesses and Intervenors

GWC

GWC expressed the following opinion:

> "The technical, economic and financial planning criteria adopted by Manitoba Hydro. . . are in keeping with the practices prevailing in the electric utility industry in Canada. A reserve capacity criteria of 12 percent . . . is adequate for a predominantly hydro system given proper maintenance practices.

> The sequence approach to generation planning . . . is also a well accepted methodology that has been used successfully by the electric utility industry for many years. It evolved out of the difficulties experienced in comparing the economics of generating plants having different construction and operating costs, different operating characteristics, and different economic lives. The use of sequences of development which extend many years into the future eliminates, or at least reduces, the effects of these dissimilarities and allows more direct economic comparisons to be made."

(GWC, Pre-filed Testimony, pages 6-7)

WRA

WRA initially concluded that Manitoba Hydro's reserve margins were too high:

> "Manitoba Hydro's plans reflect installed reserves somewhat higher than one would expect on an all-hydro system, and, in many years, higher than its target. This is doubly puzzling because the construction of high capacity interconnections, like those planned with Ontario, usually enables a utility to lower its installed reserve margins."
>
> "The installed reserve margin target will be higher than average after construction of the Conawapa project, and will remain high throughout the study period. This excess capacity will be costly for Manitoba Hydro and its ratepayers."

(WRA, Pre-filed Testimony, pages 21 and 73)

Manitoba Hydro responded to WRA's criticisms on pages 15-16 of its Rebuttal Evidence:

> "A reserve margin significantly lower than 12% (especially 6%) would not provide adequate assurance that Manitoba Hydro could supply the winter peak load should there be extremely cold weather (which can increase load 6%) or should there be equipment outages.
>
> WRA suggests that the sequences should maintain a relatively constant 12% reserve margin. Aside from being in error concerning the fact the criterion establishes a minimum, WRA totally ignores the requirement for hydro utilities such as Manitoba Hydro to have adequate resources to supply load during droughts. For many years in the sequences, the dependable energy supply is the critical factor determining resource requirements, not the capacity reserve criterion.
>
> Also, WRA calculates the reserve margin based on all Manitoba and export loads while it has been clearly stated in submissions and interrogatories that reserves are not required for a number of the exports."

During Manitoba Hydro's cross-examination of WRA, WRA stated that he was not recommending a 6% installed reserve margin and corrected his testimony as follows:

> "It is correct, I did misread the report, the 12% is intended as a minimum and not as a target."

(Transcript, Volume 7, pages 1650-1651)

CAC/MSOS

On page 21 of its pre-filed testimony, CAC/MSOS initially concluded that Manitoba Hydro's reserve margin was appropriate:

> "The 12% reserve margin is sufficient to accommodate significant excess capacity demand provided MH does not suffer unusually serious equipment problems during peak periods (most planned down-time for maintenance can be scheduled during off-peak periods)."

However, on page 73 of its closing argument, CAC/MSOS reversed its position on the appropriateness of the 12% reserve margin:

> ". . . reserve capacity could be reduced to 9% without significant loss in reliability. Manitoba Hydro's response to interrogatories on this issue was less than satisfactory and, as a condition to the approval of any new generating or transmission capacity, the need for the full 12% reserve, if it exists, should be demonstrated mathematically in a risk-related calculation. That way the Board can determine whether moving to a 9% factor is acceptable. The reliability evidence submitted by Manitoba Hydro suggests that it is at the high end of the range among Canadian utilities, and probably far in excess of what the majority of its customers require - or would be willing to pay for, given the choice."

Regarding Manitoba Hydro's overall planning approach, CAC/MSOS had the following praise:

> ". . . the interrogatory responses and oral testimony provided by Manitoba Hydro witnesses were both effective and reassuring. It seems clear that on every technical question of engineering or economics (with the exceptions of a few specific areas such as DSM, risk analysis and the scenario assumptions used for cost comparison purposes), we found the work of Manitoba Hydro to be uniformly of high quality and thorough. On several occasions during cross-examination when we identified apparent inconsistency and gaps in Manitoba Hydro's analysis, we were given a perfectly good explanation, which we found satisfying. Thus, to give credit where credit is due, much of the initial concern and scepticism we had about the quality of Manitoba Hydro's technical work has been relieved. With the exceptions noted above, where concerns and disagreements remain, it is generally not on technical issues but, rather, on what weight or importance to give to the answers we have received to these

> technical questions, what inferences to draw from them, as well as some of the fundamental value assumptions and judgements underlying the submissions."

(CAC/MSOS, Written Argument, pages 4-5)

Manitoba Hydro noted on page 26 of its closing argument that the 12% reserve criterion and its other planning criteria had been accepted by GWC and MIPUG.

MIPUG

MIPUG had the following observation regarding Manitoba Hydro's 12% reserve margin:

> "Manitoba Hydro has indicated that it has not used its 12% capacity reserve at any time during the past 10 years ..... and that it has not required any emergency import energy purchases over this same period ..... On the latter point, however, Manitoba Hydro has noted that firm load would have been shed on 78 occasions over this period due to loss of northern generation (all due to short-term HVDC interruptions) if interconnections had not been available with neighbouring utilities .....".

(MIPUG, Pre-filed Testimony, page 12)

On page 13 of its closing argument, MIPUG later came to the conclusion that Manitoba Hydro's planning approach was appropriate:

> "MIPUG concurs with the criteria and methodology adopted by Manitoba Hydro for the purposes of its customer-oriented economic analysis of least cost options and related sensitivity tests."

Board Findings

The Board accepts the planning criteria as discussed in this section as being reasonable and consistent with the practices prevailing in the electric utility industry in Canada. It is so persuaded by the views expressed in the testimony offered by GWC, WRA, CAC/MSOS and MIPUG. Certain of these planning criteria, particularly as they affect future rates and long-term financial targets, will be reviewed from time to time at future rate hearings.

On the particular criteria of the 12% reserve margin, the Board notes that the evidence is not conclusive. The Board notes that the 12% reserve margin is eventually endorsed by GWC and MIPUG. However, CAC/MSOS' evidence suggests that the 12% reserve margin may be too high.

The Board recognizes that the necessary capacity margin for any specific utility can only be determined by means of a reliability study and that none of the independent witnesses or intervenors have had an opportunity to make such a study. The Board therefore finds that a 12% margin is appropriate for generation planning purposes.

Load Forecast

Pursuant to paragraph 1 (d) (i) of Order in Council No. 177/90, the Board reviewed and considered Manitoba Hydro's load forecasts and forecasting methods used, as well as the relative success of previous forecasts.

Economic Outlook

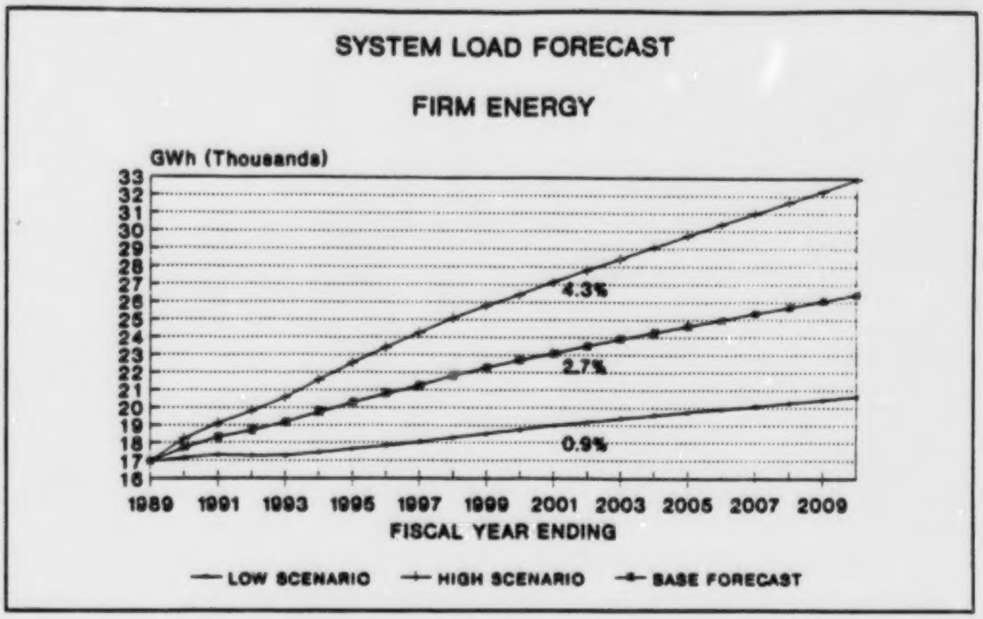
Manitoba Hydro's Economic Outlook Report (April 1989) forecasts future economic variables including changes in Gross Domestic Product (GDP), Consumer Price Index (CPI), U.S. exchange rate, interest rates, population, and employment trends. The Economic Outlook provides the basis for development of the load forecast which provides economic and financial assumptions used in the evaluation of system expansion plans was outlined in Exhibit #MH-11, Tables 8-2A and 8-2B.

Domestic Load

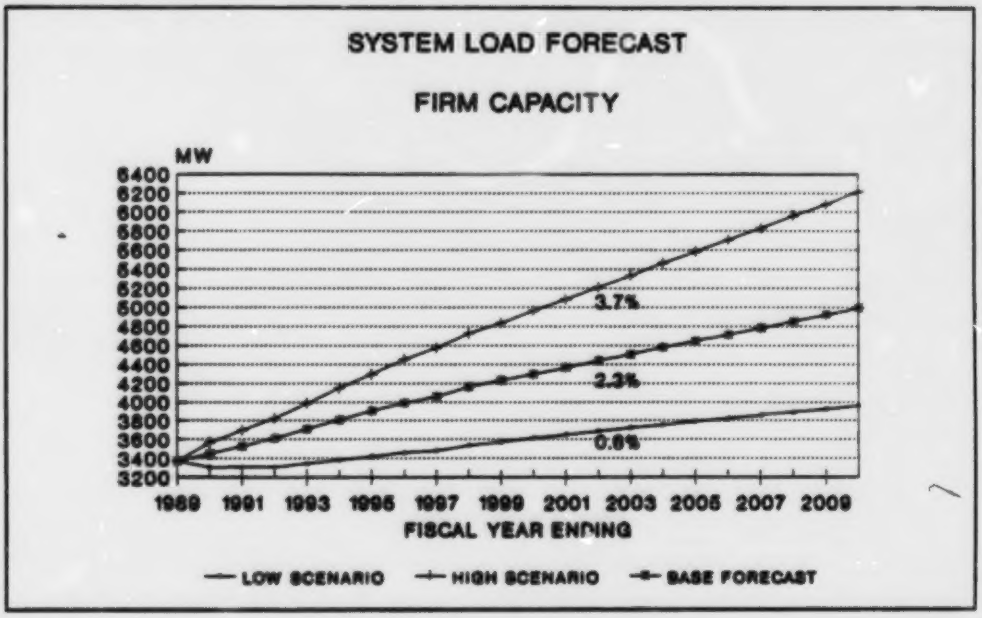
Manitoba Hydro's forecast of electrical energy consumption and peak demand is reviewed and updated annually. The forecast contains three alternative scenarios.

The base forecast is the forecast which is considered to represent the most likely future electricity requirements within the Province. The other two forecasts are called the high and low scenarios and illustrate the uncertainty associated with a long-term electricity forecast. The high and low scenarios do not represent extremes that the load might achieve, but rather they represent reasonable outcomes given a change in forecast assumptions.

The following figures illustrate future firm energy and capacity requirements for each scenario. These figures show that the ten-year weather-adjusted base forecast growth rates for firm energy and firm peak are 2.7% and 2.3% per annum, respectively. The term "weather-adjusted" means that, for calculation purposes, the effects of abnormal weather conditions have been removed. In practice, weather variations could cause annual energy and capacity to vary up to plus or minus 6% from those forecast, and monthly loads to vary up to plus or minus 10%.


SYSTEM LOAD FORECAST

FIRM ENERGY


SYSTEM LOAD FORECAST

FIRM CAPACITY

Manitoba Hydro's base forecast growth in system capacity and energy demand used for each of its seven sequences is illustrated in the following table which summarizes the load forecast from 1990-2028 as was submitted in Tables 7-1 to 7-16 of Manitoba Hydro's Submission.

System Capacity and Energy Demand

	Capacity Demand		Energy Demand	
Period	MW/Year (Average)	%/Year (Compound)	MW.h/Year (Average)	%/Year (Compound)
1990-2000	83.6	2.14	475	2.33
2001-2010	70.1	1.50	374	1.52
2011-2020	70.0	1.30	375	1.51
2021-2028	73.6	1.16	375	1.18

Forecast Assumptions

Major assumptions underlying Manitoba Hydro's base forecast are that:

1) It is assumed that natural gas will continue to be the heating fuel of choice, where it is available, for at least the next 20 years. The exception will be in some multiple family residences where individually metered electric heating systems will continue to be installed.

2) Real economic growth in Manitoba is assumed to be as follows:

1989	2.0%
1990	1.0%
1991	2.0%
1992-94	3.0%
1995 and on	2.5%

3) Average population growth in Manitoba is assumed to be approximately 4,500 people per year.

4) Housing in the Manitoba Hydro service area is assumed to increase at an average of 4,600 units per year.

5) It is assumed that customers will continue to pursue natural conservation opportunities, including more efficient appliances and processes, and better thermal insulation.

6) It is assumed that customers will continue to convert oil-based processes to electricity, for both economic and environmental reasons.

The high and low scenarios are based on different sets of assumptions. Generally speaking, the high scenario is based on the assumption of continued economic growth at the rates experienced in the late 1980's, and the low scenario on a prolonged recession in North America.

Manitoba Hydro's Forecast Methodology

For forecasting purposes, the Manitoba integrated load (i.e., Manitoba Hydro and Winnipeg Hydro combined) is divided into nine components. These components are again subdivided into as many as 70 sub-components, based on customer type and geographic location, and each component is forecast separately.

The residential components are forecast using primarily econometric techniques, modified to incorporate the major end-uses of electricity in the home. Residential consumption represents about 29% of sales (excluding Winnipeg Hydro).

The Farm components are forecast using simple trend techniques. Farm consumption represents about 10% of sales.

The General Service component is forecast by analyzing the electricity requirements of each industry type. The forecast for this sector is presented in two groups - under and over 10 MW. The rate of increase in the under 10 MW load is related to the rate of increase in real gross domestic product (RGDP). However, recognizing the increasing energy efficiency of most industries, as well as the increasing importance of the service sector in the economy, this is not a direct relationship, and the overall consumption per RGDP is assumed to reduce. The twelve existing customers over 10 MW, plus potential new customers in this group are assessed individually, usually in consultation with the customers themselves. No specific allowance is made for any as yet unidentified major loads which could occur. General Service (under 10 MW) represents about 32% of sales, while General Service (over 10 MW) represents about 28%.

Miscellaneous Services, including no-longer-offered flat rate services, lighting and seasonal customers, and accounting for about 2% of sales, are forecast by analysis of trends.

The component called Distribution Losses and Unaccounted Energy is forecast based on experience and is about 4% of sales.

The Construction component represents the energy used by Manitoba Hydro and its contractors on the major construction sites and is forecast as part of Manitoba Hydro's Capital Plan. This component is typically about 1% of sales.

The Winnipeg Hydro component accounts for approximately 15% of the Manitoba firm load. Winnipeg Hydro is responsible for forecasting their own sales and distribution losses, and these values are incorporated into the system load forecast.

System Transmission Losses represent the energy consumed in moving power from the generating stations to the distribution system. The amount depends upon the loading of the system and typically runs at around 10% of total energy requirements.

For load forecasting purposes, it is assumed by Manitoba Hydro that efforts to promote 'natural' conservation will continue at the same level experienced over the last decade. The conservation due to these efforts is incorporated into the forecasting techniques and is further discussed in the section entitled, "Meeting the Load Forecast".

The base forecast does not incorporate the effects of the demand-side management programs. Manitoba Hydro considers a load reduction due to demand-side management to be a generation source and therefore does not double-count the load reduction by including it as part of the load forecast. In the event that load growth is greater than forecast, the excess may be offset if the DSM program produces better results than anticipated. The domestic load that must be satisfied by Manitoba Hydro is the arithmetic sum of the load forecast and the DSM program. If the DSM program is successful in reducing the load more than anticipated, the two will cancel and the resulting load that must be satisfied will be fairly close to that predicted.

Similarly, if the load growth is lower than forecast and the DSM program is less successful than anticipated, the two will again tend to cancel. If both the load forecast and the DSM program deviate in an unfavourable direction, the resulting load which must be handled will increase or decrease depending on the degree of deviation. For example, if DSM is not as successful as anticipated and the load relating to the load forecast is higher than anticipated, the net effect on the system is an increase in domestic load. The converse would result in a decrease in domestic load.

In summary, the DSM program will temper the results of the load forecast and vice versa so both of these factors must be considered together.

The load forecast excludes power requirements that are expected to be supplied through customer generation. It is estimated that approximately 60 GW.h/year is currently supplied and consumed by customers operating their own facilities. Based on the stated intentions of certain customers, this is expected to increase to about 300 GW.h/year by 2000. However, this energy and the related capacity is specifically excluded from the system load forecast and is not included in any of the alternative scenarios.

Position of Independent Witnesses and Intervenors

GWC

GWC had the following observations regarding Manitoba Hydro's load forecast:

> "Given the relatively modest growth of demand (less than 90 MW annually on average for the next twenty years) and the lead times required today to move new facilities from the conceptual stage through to commissioning (ten to twelve years), opportunity exists for Manitoba Hydro to initiate remedial actions should a forecast error become apparent. These actions could involve accelerating or decelerating construction schedules, arranging purchases from other utilities, calling upon reserve capacity, or putting in place other measures to compensate for errors in the load forecast as they become apparent and so long as they are not excessive. Load forecasting accuracy becomes less

> critical when the annual growth is small and there are multiple supply options from which to choose.
>
> Some seven to ten years ago, forecasts made only a few years in advance were quite inaccurate and the opportunity to affect corrective measures along the lines outlined above would have been limited. However, the more recent forecasts clearly exhibit an improving trend in that forecasts made, for example, up to eight or nine years in advance of the 1987/88 and 1988/89 load years were reasonably close to the final weather-adjusted value. While it is difficult to say if this accuracy level will be sustained, nevertheless it does provide encouragement that the forecasting process is working."

(GWC, Pre-filed Testimony, pages 8-9)

The Board notes GWC's positive views on Manitoba Hydro's forecasting accuracy.

WRA

WRA had the following criticism:

> ". . . Manitoba Hydro has not reflected different relative prices of electricity to gas for different sequences by developing sequence-specific load forecasts for each sequence. Manitoba Hydro's position appears to be that price elasticity effects would not change the relative ranking of various sequences . . ."
>
> "To ascertain that the load forecast would not be substantially different under different sequences, Manitoba Hydro should develop sequence-specific load forecasts for the seven sequences. If it is found that the sequence-specific load forecasts are not substantially different, one can conclude that price elasticity effects would be insignificant."

(WRA, Pre-filed Testimony, pages 67-68)

WRA's concerns are dealt with by Manitoba Hydro at the end of this section.

CAC/MSOS

CAC/MSOS initially stated:

> "Because the current expansion plan deals with Manitoba Hydro's decision related to demand ten years to almost forty years into the future, it is Manitoba Hydro's long run forecasting accuracy that is of greatest concern.
>
> On average, forecasts had a consistent tendency to be high, a lesson that should be remembered when using the current forecast to plan future expansion of the system."

(CAC/MSOS, Pre-filed Testimony, pages D-1 and D-2)

CAC/MSOS's opinion on Manitoba Hydro's load forecasting and the impact of unpredictable occurrences developed and changed during the public hearing (Transcript, Volume 9, pages 2122-2134). CAC/MSOS noted that Manitoba Hydro's forecasting technique changed roughly 10 years ago which substantially improved load forecast accuracy. CAC/MSOS then reviewed Manitoba Hydro's load forecasts dating back as far as 30 years and the impact of new forecasting methodology over that period. CAC/MSOS concluded the following:

> "One thing is fairly apparent. The forecasting seems to be much better. Over the 10 years, it has tended to be on the low side, although it has come up."

(Transcript, Volume 9, page 2126)

This conclusion reversed CAC/MSOS' earlier statement that Manitoba Hydro's load forecasts had a consistency tendency to be high. However, CAC/MSOS qualified its conclusion regarding its confidence in Manitoba Hydro's load forecast:

> ". . . forecasting almost invariably, certainly in this case, assumes stability. All assumptions in Manitoba Hydro's forecast assume constant trends or relatively constant trends.
>
> The real world, though, is inherently unstable. There are shocks to the system, as we call it. There are periods of stability interspersed with major shocks. The longer the time frame of a forecast, the more likely it is or the surer it is that this forecast will be affected by some serious shocks.
>
> For example, looking to the future we can speculate, we can't predict shocks, which is why forecasting is hard, and this is not a criticism of the forecasting methods used because inherently, you cannot predict shocks, by definition."

(Transcript, Volume 9, pages 2126-2127):

On page 10 of its closing argument, Manitoba Hydro agreed that "shocks" cannot be forecast, but submits that for the most part, the types of shock that can be envisioned will tend to reinforce the Preferred Development Plan as was discussed during the public hearing (Transcript, Volumes 3 and 14, pages 519 and 3264, respectively).

CSC

CSC's concerns were as follows:

> "The 1989 Load Forecast is likely to overestimate future demand, but it is difficult to quantify this upward bias without additional documentation and analysis. The 1990 Load Forecast presents a somewhat lower estimate of provincial consumption, and it indicates that some methodological improvements have been made. Nonetheless, it is still likely to be upwardly

> biased, since it relies on customer-supplied forecasts and may not fully incorporate the effects of naturally occurring conservation."

(CSC, Pre-filed Testimony, page 17)

> ". . . CSC remains concerned about Manitoba Hydro's load forecasting techniques and recommends to the Public Utilities Board that a proceeding be conducted to evaluate Manitoba Hydro's load forecasting techniques. Such a proceeding, amongst other things, would ensure that demand-side management and load forecasting were fully integrated.
>
> Other concerns include the use of customer-supplied forecasts and the methodology for extrapolating the forecast beyond the year 2009.
>
> The submission found on page 11 of the Manitoba Hydro argument suggests that natural conservation has now been incorporated into Manitoba Hydro's load forecasting. To the extent that this is the case, a load forecasting review should be simplified."

(CSC, Written Argument, page 17)

CSC's concerns are dealt with by Manitoba Hydro at the end of this section.

MIPUG

MIPUG's comments in its pre-filed and final argument were as follows:

> "Manitoba Hydro has presented graphs in its Load Forecast that are suggested to illustrate that long-term forecast accuracy is improving; however, it remains important to appreciate the potential impacts from major shocks which adjust growth rates and eventually forecasts. In a period of low growth rate predictions, such as the present, an obvious concern is potential risk that future events could shift load growth upwards."

(MIPUG, Pre-filed Testimony, page 8)

> "Manitoba Hydro load forecasts and forecasting methods, as relevant for the purpose of this hearing, are reasonable and appropriate (no evidence has been provided to suggest that the present decisions should be based on any forecast other than the Manitoba Hydro 1990 Load Forecasts)."

(MIPUG, Written Argument, page 3)

In summary, Manitoba Hydro's load forecasts were criticized by WRA and CSC for:

1) Being biased on the high side.

2) Relying on customer-supplied forecasts which result in over-stated requirements.

3) Underestimating natural conservation.

4) Not recognizing the possibility of different load growth patterns for different scenarios.

These criticisms were answered in pages 64-76 of Manitoba Hydro's Rebuttal Evidence which was filed as Exhibit #MH-3B during the public hearing. A summary of that response is provided below.

1) Alleged Bias:

The accuracy of forecasts prepared in the period 1980 to 1990 have consistently improved and current forecasts tend to be on the low side. Manitoba Hydro draws five conclusions:

a) There was a sharp change from 1979 to 1980. In 1979, the sales disaggregated forecast technique was used for the first time and thus, the 1979 forecast is a transitional one which cannot be viewed in the same light as subsequent forecasts.

b) For every forecast prepared in 1980 or later, the actual weather-adjusted consumption for every year has been within +/- 8%.

c) Any tendency to over-forecast has been corrected. Successive forecasts have tended to become more accurate.

d) Recent forecasts have tended to under-estimate the load.

e) The first three years after the new technique was used were transition years. After that actual energy and capacity values have stabilized at approximately 10% and 12% lower, respectively, than those forecast in 1979. For the year 2000, the May 1990 forecast of 4,286 MW and 22,240 GW.h is 19% and 15% lower respectively than the 1979 forecast of 26,073 GW.h and 5,315 MW.

Manitoba Hydro considers that +/- 8% is satisfactory in light of the number and variety of assumptions and predictions that have to be made. There is no guarantee that the present forecast of future consumption has the same accuracy. However, since the same basic forecasting techniques are used, as well as alternate techniques which provide useful checks, and since the quality and quantity of basic data is continually improving, it is reasonable to use the forecast with a high degree of confidence.

2) Reliance on Customer-Supplied Forecasts:

Manitoba Hydro has two responses to the argument that reliance on customer-supplied forecasts results in over-stated requirements.

First, customer-supplied forecasts are very rarely incorporated exactly as supplied. Manitoba Hydro does not consider Winnipeg Hydro to be a customer in the strict sense of the word, but it is the only 'customer-supplied' forecast that is consistently used unchanged. Other customer-supplied forecasts are adjusted on a variety of factors including accuracy of previous forecasts, assessments of market conditions, expected raw product reserves and anticipated demand.

Secondly, experience to date has not substantiated the allegation that customers tend to forecast high -- if anything, the opposite has been true. Winnipeg Hydro's forecasts have tended to under-estimate consumption. It has been Manitoba Hydro's experience that major customers tend to under-estimate their long-term requirements as much as they over-estimate them. Local plant management may plan and budget on a conservative basis, but often find it opportune to increase production or to take advantage of sudden opportunities. Furthermore, management may prefer to keep its strategic intentions secret by not telling anyone, including Manitoba Hydro.

3) Underestimation of Natural Conservation:

Manitoba Hydro states that the evidence has been misinterpreted.

Over the last fifteen years, Manitoba Hydro and the Manitoba Government have made a concerted effort to practise conservation, and considerable natural conservation is presumed to have resulted. The derived econometric equations and average end-uses incorporate this natural conservation and are used to predict future loads.

Natural conservation is incorporated into the load forecast to the same extent as it has been experienced over the last ten to fifteen years. There is no evidence to suggest that natural conservation is going to increase, particularly in the light of predicted reductions in the real cost of electricity.

4) Lack of Scenario-Specific Load Forecasts:

Manitoba Hydro argues that the electricity prices calculated for each scenario should be used to create a new forecast specific to that scenario. Presumably, this would lead to a new sequence optimization and a new rates scenario, resulting in a second new load forecast, and so on until convergence is achieved.

In theory, this is true; in practice, it is impossible. Each cycle takes about six months to perform properly, so it is unlikely convergence would ever be achieved prior to the next annual cycle having to commence. An approximation is achieved by using the results of each year's Integrated Financial Forecast in the next year's Economic Outlook and Load Forecast.

During the public hearing, Manitoba Hydro also testified that the forecast represents its best estimate of future demand in the province, with an equal chance of being too low or too high (Transcript, Volume 5, page 1027) and that the load will be within plus or minus 240 MW of the base forecast by 2000. Manitoba Hydro's analysis of recent forecasts has shown that if anything, there is a tendency to under-forecast the Manitoba Hydro requirements (Transcript Volume 2, page 231).

The Board notes that the Manitoba Hydro forecast is at the low end of the average 2.3% that was used by Ontario Hydro for a 25-year planning horizon (Source: Ontario Hydro, Providing the Balance of Power) and is well below the 3.02% rate of growth experienced in Manitoba over the decade ending in 1990 (Source: Manitoba Hydro Annual Reports). New Brunswick Power's latest load forecast in November 1989 reflects an annual growth rate of 3.2% over a 15-year period.

Board Findings

The criticisms made by intervenors do not, in the Board's opinion, provide grounds for rejection of Manitoba Hydro's load forecast.

The Board notes Manitoba Hydro's testimony that its base forecast represents its best estimate with an equal probability of being too high or too low. Nevertheless, it must be recognized that the forecast depends on assumptions regarding demographic and economic growth, on electricity's share of the energy market, and on hydrocarbon fuel prices, any of which might diverge from present perceptions.

Manitoba Hydro is projecting cost of service increases which are on average below the rate of inflation, that is, they will decrease in real terms. This contrasts with the general expectation that oil and gas prices will increase in real terms. This expectation is shared by Manitoba Hydro, as indicated in its use of 3% per year escalation in costing gas turbine generation. Decreasing real prices for electricity and increasing real prices for gas and oil may encourage future shifting of heating and cooking loads from hydrocarbon fuels to electricity.

Manitoba Hydro's forecast was made after a period of several years during which hydrocarbon fuel prices were falling in real terms and the Board is concerned that the future may see a long-term reversal of this trend. The Board therefore tends to share the opinion expressed by MIPUG regarding the risk of an upward shift of load growth.

The Board accepts Manitoba Hydro's base case forecast for the purpose of generation planning,-but for the reasons outlined above considers that it is more likely to be an underestimate than an overestimate.

Meeting the Load Forecast

In the previous section, the Board accepted Manitoba Hydro's load forecast for the purpose of generation planning. This section examines the options advanced by Manitoba Hydro to ensure future power availability. Manitoba Hydro's future generation options can be categorized as demand-side options and supply-side options. The generation expansion scenarios proposed by Manitoba Hydro (which are discussed in the following section entitled, "Manitoba Hydro's Alternative Supply Scenarios") are essentially combinations of programs that reduce customer demand (demand-side options) and new sources of generation (supply-side options).

Demand-Side Management Options

Board Overview

In the course of reviewing the evidence presented on demand-side options, the Board came to the conclusion that it is important to define the following options:

1) Naturally Occurring Customer Conservation

Natural conservation occurs when customers act on their own initiative to reduce their electricity requirements. For example, residential customers will install weather stripping, add more insulation, set back thermostats, and generally reduce their electricity requirements. Industrial and commercial customers reduce their electricity requirements by implementing demand control, load shifting, high efficiency processes, more efficient lighting and higher insulation factors. Each class of customer acts in these ways to reduce electricity consumption either because they want to save money or because they believe in the conservation ethic (or both).

2) Information-Based Conservation Programs

Information-based conservation programs are undertaken by utilities, governments and conservation groups. Examples of such programs undertaken by utilities such as Manitoba Hydro include the establishment of facilities to encourage consumers to purchase higher efficiency appliances and equipment, and the use of bill stuffers to advise on the prudent use of electricity. Government programs such as the former HOME CHEC-UP program in Manitoba also encourage conservation of electricity. Lastly, conservation groups distribute information to educate the public on the proper use of non-renewable resources and the reduction of pollution.

3) Demand-Side Management (Strategic Conservation)

Demand-side management programs are strategic actions undertaken by utilities in order to bring about customer efficiency improvements which lead to planned reductions in demand and energy. The rationale for this process is that residential, commercial and industrial customers will come to the conclusion that certain

> conservation efforts involve upfront costs which are too high or have too long a payback period.
>
> Thus, utilities pursuing such DSM strategies must produce information packages providing certain incentives or subsidies which in their view are sufficient to bring about the desired action by customers and lead to the planned reductions in demand and energy.

The cost of such DSM programs will, however, be limited to the value of the avoided costs because utilities are obliged to provide service at the lowest reasonable cost to consumers.

The Board notes that naturally occurring customer conservation, as well as information-based conservation programs are included by Manitoba Hydro in their load forecast.

Manitoba Hydro Evidence on DSM

Manitoba Hydro's Definition of DSM and Perceived Options

Manitoba Hydro's Submission, in Appendix 17 (pages 1-2) indicates:

> Demand-Side Management (DSM) is a term used by the utility industry to refer to a group of actions designed to change the nature of its customers' electrical usage. Manitoba Hydro testified that their DSM programs must meet the following objectives:
>
> a) No negative impact on customer lifestyle, benefits, or productivity,
>
> b) Lower total utility revenue requirements,
>
> c) Cost of implementation at or below the avoided cost of supply.
>
> DSM activities involve encouraging customers (through information and incentives) to modify their energy consumption. Manitoba Hydro's goals of DSM are based on their commitment to promote programs when they can be achieved more economically than supply with little or no adverse environmental impacts.

Manitoba Hydro's Perceived Options

The Board notes from Manitoba Hydro's Submission (Appendix 17, pages 1-2) that Manitoba Hydro DSM options fall into three classifications. These classifications are discussed below:

1) Energy Conservation

Effective energy conservation involves using less electricity to obtain comparable or superior services.

2) Load Management

Load management is designed to improve the time distribution of overall energy consumption. Load management modifies energy demand at a particular time or shifts demand from one period to another in order to allow the optimal use of utility generation and transmission facilities. Interruptible power programs, for example, make it possible for the utility to reduce peak demand.

3) Customer Generation

Customer generation occurs when customers generate power for their own use. For example, Repap Forestry Products in The Pas uses wood waste to generate their own power.

Present Manitoba Hydro DSM Programs

During the 1989/90 fiscal year, Manitoba Hydro initiated a rebate program for customers who purchased outdoor timers. The timers are intended to lower energy consumption and reduce the utility's peak load. More than 6,000 rebates of $5.00 per customer have been provided under this program. The program has been continued into the 1990/91 fiscal year.

Manitoba Hydro experts are working with Manitoba industries to provide the latest information on new techniques that would improve energy efficiency.

Manitoba Hydro's Future Plans for DSM

1) Management Commitment

The Board noted during the public hearing that Hydro and various intervenors agree that management must be fully committed to the DSM concept. That commitment is a necessary (but not sufficient) condition for success. Such statements are often regarded as truisms; in the case of utilities, however, it is essential that management be seen on the side of DSM because DSM is a challenge to the typical corporate culture of a utility.

Utilities have heretofore seen themselves as promoters and providers of electricity. In such a culture, the Board presumes that it is natural for engineers to have a dominating position.

Changing that culture to a degree by introducing DSM programs requires the use of marketing experts and even sociologists. In short, DSM requires that the utility better understand the consumption needs and preferences of its customers.

Mr. Ransom stated, for example:

> ".....the Corporation is committed to DSM and that management will provide the necessary attention and resources to DSM regardless of the level and extent of other activities under way."

(Transcript Volume 18, page 4015)

Manitoba Hydro's DSM Target

Manitoba Hydro established that the purpose for the DSM target is for use in system planning. Their short and long range planning is based on the assumption that the targets established will be achieved.

Their target is a 100 MW reduction in capacity requirement at peak load and a 500 GW.h reduction in firm annual energy requirement at the point of generation by 2001. These targets are in addition to the load reduction anticipated by natural conservation and from the current information-based conservation programs.

The 100 MW target was not developed through analysis of opportunities specific to Manitoba Hydro, but is based on information and experience gained by other utilities which have had programs in operation for some time. Manitoba Hydro states that their target is an estimate which they feel is consistent with the experience of other utilities.

A collaborative process is required to effectively develop and implement DSM programs with all interested groups, consumers, environmental groups and Winnipeg Hydro. A successful program is dependent on Winnipeg Hydro's support and implementation of programs; therefore, these programs must be developed in concert with those of Manitoba Hydro.

The target is expected to be met through customer programs, Manitoba Hydro's internal conservation programs and customer generation. A breakdown of their expected contribution to each of these three components is as follows:

Breakdown of Target for DSM

	MW	**GW.h**
Customer Conservation	85	425
Manitoba Hydro Conservation	10-15	50-75
Customer Generation	0-5	0-25
Total	100	500

Customer Conservation

Customer conservation programs are aimed at reducing customer use of electricity without sacrificing customer service, productivity, or comfort. The target is 85 MW at the winter peak and 425 GW.h of annual energy. Customer conservation targets have been broken down into the residential, commercial and industrial sectors.

Targets Achievable by 2001

	MW	GW.h
Residential	30	150
Commercial	30	150
Industrial	25	125
Total	85	425

These targets are preliminary, and are based on initial screening of residential and commercial program concepts. The industrial sector target is not based on an analysis of individual conservation opportunities but, because power sales to all three sectors are approximately equal, the industrial target was established at a level roughly the same as the other two sectors.

Manitoba Hydro Conservation

This target is aimed at reducing Manitoba Hydro's electricity use. This includes energy and capacity losses due to the transmission, transformation, and distribution of power as well as the use of electricity in corporate buildings and generating stations. Because Manitoba Hydro uses approximately 15% of its total firm domestic load, the corporate conservation target was set at 15% of the total demand management target. This is approximately equal to 10-15 MW at the winter peak and 50 to 75 GW.h of annual energy.

Customer Generation

The customer generation target will consist of programs aimed at promoting customer generation of electricity for their own use. This target is for up to 5 MW of capacity and 25 GW.h of annual energy.

Manitoba Hydro notes that as further economic conservation potential is identified and experience is gained, the targets can be adjusted accordingly.

In response to criticism from intervenors regarding Manitoba Hydro's conservative approach to DSM, Mr. Lambert stated:

> "....the Manitoba Hydro demand-side management target is a reasonable goal until estimates of achievable conservation are made. We do not know how successful these programs will be, but Manitoba Hydro now has a commitment to a target which provides an opportunity for the corporation to establish a more realistic estimate of what is achievable at the avoided cost. Failure to achieve the current Manitoba Hydro demand-side management target, affecting in-service date of generation by one year, is a manageable risk. The risk of setting too high a demand-side management target, delaying the Conawapa in-service date, and then failing to achieve the target are unacceptable in terms of meeting Manitoba Hydro's mandate to supply our load and in terms of financial justification."

(Transcript, Volume 2, page 232)

Cost of DSM

Based on the estimates and experience of other utilities, Manitoba Hydro estimates that it will spend between $50 and $100 million on DSM programs in order to achieve its target. There is also a cost borne by the customer to implement programs and this is estimated by Manitoba Hydro to be $50 to $100 million. When the customer cost is added to the utility cost, the total societal expenditure on demand-side management is estimated at $100 to $200 million.

The following table summarizes the estimated utility and societal costs in total dollar terms and on a cost per kW.h basis for Manitoba Hydro and other utilities.

Comparison of DSM Costs to 2000
(In Millions of 1990 dollars)

	Total Load GW.h	**Target GW.h**	**Total Utility Cost ($M)**	**Total Societal Cost ($M)**	**Unit Utility Cost (kW.h)**	**Unit Societal Cost (kW.h)**
B.C. Hydro	60,000	3000	294	720	1¢	2.4¢
Ont. Hydro	185,000	10000	1000	3000	NA	3¢
Hydro Que.	160,000	9000	1500	NA	1.7¢	NA
Man. Hydro	23,497	500	50-100	100-200	1¢-2¢	2¢-4¢

NA = Not available

At a utility cost of 1¢ to 2¢ per kW.h, Manitoba Hydro can currently afford to invest 10¢ to 20¢ per kW.h assuming that the average conservation investment has a useful life of 15 years. As a result, it can budget 50 to 100 million dollars for demand management to achieve its 500 GW.h target. For example, if an outdoor timer saves the customer 400 kW.h per year and has a useful life of 15 years, Manitoba Hydro can spend from $4-$8 per year or from $40-$80 million in total considering the time value of money; however, some assurance is required that the 15 year-life is reasonable before an expenditure of this magnitude is considered.

The following quote from Manitoba Hydro's Perspective 2000 report (page 29) summarizes the overall objective of the demand-side management program and recognizes the uncertainty associated with the achievement of the 100 MW DSM target:

> "The overall objective is to determine the mix of demand-side and supply-side options that best meet both the customers' demand for energy and result in the lowest overall cost of power to all customers. It is anticipated that, as a result of this process, the Corporation will adopt selected programs that conserve energy or reduce peak demand at a cost less than the long-term marginal cost of supplying that power. Any DSM programs adopted will be designed to ensure that the energy needs of Manitobans will be met without adversely affecting their quality of life."

(Exhibit #MH-2(b))

Manitoba Hydro's evidence states that the nature, size and potential benefits of such programs to Manitoba Hydro are not presently known. Experience in other utilities is of limited value, because there are few predominantly hydraulic utilities with comparable low energy prices operating in a similar climate. The primary uncertainty about these programs is customer participation or market acceptance and its long-term effect on electricity use and load shapes.

Proposed DSM Programs and Support Activities

During 1990/91, four DSM programs will be implemented. These programs have cumulative load reduction targets of approximately 22 MW and 80 GW.h by 2001....representing 15%-20% of the overall corporate target. In addition, during 1990/91, three pilot projects will be tested in anticipation of full-scale program implementation next year.

Furthermore, there are a number of program support activities which have no direct customer impact but are necessary for developing and implementing programs. These include energy efficiency standards for new appliances and new construction, developing a commercial sector Data Base and acquiring computer software.

The proposed DSM programs, pilot projects, and support initiatives are summarized as follows:

1990/91 DSM Programs and Support Activities

	Manitoba Hydro Total Cost (To 2001)	Maximum Annual Impact
Deliverable Full-Scale Programs		
Sentinel Lights	$2-4 million	2 MW, 9 GW.h
Street Lights	$8-16 million	7 MW, 28 GW.h
Outdoor Timers	$1.4 million	9 MW, 26 GW.h
Infra-red Agricultural Heat Lamps	$250,000	2 MW, 12 GW.h
Pilot Projects		
Efficient Showerheads (Residential)	$ 20,000	Experimental
Efficient Showerheads (Commercial)	$ 20,000	Experimental
Electric Home Weatherization	$150,000	Experimental
Support Initiatives		
Corporate Conservation Plan	NA	NA
Efficient Appliance Standards	$ 20,000	NA
Efficient Housing Standards	$ 50,000	NA
Communication to the Public	$4 million	NA
Commercial Energy-use Database	$100,000	NA
Computer Software	$ 50,000	NA

The costs to implement the programs will be reflected in the domestic rates. In the long-term, all consumers will benefit from the general lower costs resulting from DSM, but those consumers who participate in the programs will enjoy immediate reductions in their billing depending upon the extent of their participation.

It should be noted that the estimate of a $50 to $100 million expenditure on demand-side management by Manitoba Hydro is incremental to the current expenditure of two million dollars on energy management and information programs by Manitoba Hydro since the current load forecast assumes that these programs will continue into the future.

Manitoba Hydro's View of Avoided Costs

The Board had ample opportunity to be made aware of the crucial nature of the evidence and discussion concerning the relationship between DSM plans and avoided costs. Hydro states:

> "The underlying goals of Demand-Side Management (DSM) are based on Hydro's commitment to promote conservation of electricity when it can be achieved more economically than supply....."

(Manitoba Hydro Submission, Appendix 17, page 1.1)

Manitoba Hydro's evidence indicated as follows:

Avoided costs are the bases for determining the amount of DSM that can economically be achieved. These costs are made up of three components:

1) The amount saved by deferring the next generating plant and associated transmission including operating and overhead costs,

2) The amount saved by incremental change in load, affecting system production costs which include fuel and water rental,

3) The amount saved in deferring electrical distribution system changes.

The determination of the avoided costs available for all DSM programs is based on the long-term marginal cost of supplying that power. Manitoba Hydro uses long-term generation scenarios to determine this marginal cost by simulating the scenarios with and without DSM.

The determination of the value of a specific DSM program is complex. For example, the time of day, month, season, that will affect a load change must be considered. The value of avoided costs is lowest in summer and highest in winter; it is also lower during utility off-peak periods. The greatest avoided costs are available to programs affecting the winter system peak, when river flow is the lowest and the demand for electricity is the highest. During the summer, Manitoba Hydro's avoided costs are 2.3 to 2.8 cents per kW.h. In winter on-peak, the avoided costs are about 6.8 cents per kW.h in 1990 dollars at the customer's meter.

During the hearing, Mr. Zaleski defined avoided costs,

> ". . . it's recognized that we must expand our generation and transmission system to meet growing loads, and if the load growth were lower, then future expansion plans would be delayed and therefore we would have savings.
>
> Now, the savings result from deferred generation additions, they also result from deferred transmission and distribution additions, and they also result from changed operation of our system, and that is, what I mean by the changed operation of the system is that for Manitoba Hydro's particular system, when we add large plants there are many years between the addition of generating plants; therefore, there are many years between benefits or savings resulting from delay of these plants. Even in those intervening years, a reduction in the load has a value to us and that value is related to what we could export the additional surplus energy for.
>
> Well, how did we determine the value or the avoided cost of a lower load growth? What was done was we looked at the expansion of our system without the DSM program targets and then we compared that to the costs of expanding the system with the DSM program that is included in our submission, and that's the 100 megawatt target by 2001, growing at about 4

megawatts per year, so looking at the difference in the cost to expand our system with and without the demand management program resulted in an indication of the dollar savings that were achievable by the lower load growth, and that, those savings when levelized into constant dollars per year which escalate with time, that divided by the energy saving from the DSM program gives the avoided cost in cents per kilowatt hour.

I should also mention that avoided cost could also result not only from reduced load from our DSM program, but there could also be savings resulting from supplies, say, for example, by non-utility generators, so the supply from a non-utility generator also results in avoided costs on our system."

(Transcript, Volume 5, pages 1059-1061).

Manitoba Hydro's DSM Targets: Comparison with Other Utility Targets

Manitoba Hydro compared its DSM targets to those of other utilities and reported on them as a percentage of the estimated firm energy needs in the year 2000 as follows:

Comparison of DSM Energy Targets

Utility	Customer Conservation	Corporate Conservation	Customer Generation	Known Total
Hydro Quebec	5.6%	NA	NA	5.6%
B.C. Hydro	5.9%	NA	NA	5.9%
Ontario Hydro	5.4%	NA	1.3%	6.7%
Manitoba Hydro	2.2%	0.3%	0.1%	2.6%
U.S. Average	2.2%	NA	1.0%	3.2%

NA = not available

(Manitoba Hydro Submission, Appendix 17, page 2.5)

The above table indicates that the customer conservation targets for B.C. Hydro, Ontario Hydro, and Quebec Hydro are significantly higher than the Manitoba Hydro target (other Canadian utilities have not set targets). However, these three utilities are leading utilities for energy conservation in North America and have had experience in this field within their respective jurisdictions.

The Manitoba Hydro customer conservation component of the DSM target is 2.2%, equivalent to the U.S. average estimate. The overall Manitoba Hydro target is lower than the U.S. average, however, due to Manitoba Hydro's customer generation estimate which is only .1% compared to the U.S. average estimate of 1.0%.

Manitoba Hydro's low target is also ascribed to the fact that their retail rates are among the lowest in North America. Utilities with low avoided costs and low retail rates have more difficulty in economically achieving similar targets than utilities with high avoided costs and high retail rates.

Manitoba Hydro has indicated that they will apply a 10% adder to avoided costs when evaluating the cost-effectiveness of DSM programs to assure that a program is a contender, against supply options.

Position of Independent Witnesses and Intervenors

The intervenors and independent witnesses took similar positions on Manitoba Hydro's demand-side management program. With two exceptions, they are all of the opinion that the program targets are lower than what appears to have been accepted by other electric utilities. Their opinions are based on data from their respective jurisdictions rather than from that of Manitoba Hydro. Manitoba Hydro emphasizes that their DSM program is still in its infancy and that the target can be adjusted as the results of the initial programs are determined and as they become more experienced.

CSC

In CSC's final argument, on page 2 and on page 21,

> "The Public Utilities Board should order Manitoba Hydro to redesign its DSM programs to....achieve by the year 2000 savings four to seven times as great as the current program....The DSM programs proposed by Manitoba Hydro fall far short of what is necessary even in the short term. Some of the most severe problems with Manitoba Hydro's proposed programs are their very limited scope, failure to target any substantially meaningful portion of the true potential market, lack of aggressive efforts to capture significant market penetration, and absence of sufficient detail to allow for a thorough and proper review".

(Written argument, pages 2, 21, 61 and 62)

CSC's Surrebuttal Testimony also stated,

> "As we so clearly state, there is substantial uncertainty as to how much conservation can be achieved. Ideally, Manitoba conservation estimates should be based on province-specific experience ...".

(Surrebuttal Testimony, Exhibit #CSC-66, page 61)

> "... we suggested an interim target of 7% to 15% as achievable by the year 2000 as a planning assumption. However, as we state in our direct and surrebuttal testimony, these estimates should be firmed up with an accelerated program of studies, pilot and full scale demand-side management programs."

(Transcript Volume 13, page 2929)

Manitoba Hydro stated,

> "The risk of a DSM target that is too high and not achievable is that insufficient investment is made in supply options resulting in power shortages and a high cost of purchasing power from neighbouring utilities as well as wasted investment in conservation programs. Targets that are low require a conservative investment, consequently slower results, but when recognized, targets can be increased and the flexibility of deferring new plant construction utilized."

(Transcript Volume 3, page 514)

In regard to the costing of DSM programs, CSC has taken the approach that Manitoba Hydro's avoided costs are too low because they are excess capacity driven.

CSC contend that hydro power comes on line in chunks of 100 to 1,300 megawatts and produces large volumes of excess capacity, so avoided costs are low just after new hydro is added. Avoided costs start to rise as the excess capacity is used up, but just at the point when the excess capacity is gone, a new block of excess capacity from a new hydro plant is added, depressing avoided costs again.

Manitoba Hydro submits that their approach to avoided costs are clearly reasonable and fair. Their approach accounts for the impact of large hydro plants being added and the effects on system costs. The Manitoba Hydro approach provides a realistic consideration of all factors affecting future costs to the utility. It incorporates the specific characteristics of the Manitoba system such as capacity and energy requirements, operation of the hydro-thermal system, interruptible exports, imports, fuel and future modifications that are expected such as load growth, timing of new plants, new tie lines and changing costs. Because plant capacities are larger than annual load growth increments, it will take time for each new plant to be fully utilized by Manitoba firm load. This is extremely common in the utility industry. Supply side additions are always "lumpy".

CAC/MSOS

On pages 70 and 77 of their argument CAC/MSOS stated,

> "Manitoba Hydro should be required to get serious about DSM and to develop a real DSM project as part of a new operating philosophy of promoting conservation as a precondition to the approval of the construction of any new generation or transmission facilities.
>
> "Manitoba Hydro should, as a precondition to the construction of any generating station, have to develop a DSM plan that is at least four or five times as ambitious as the current plan."

GWC

GWC commented,

> "I share the view....that the DSM targets....do not seem to be particularly challenging....I can't tell you what the right target might be, but I would have thought that something that caused the utility to stretch itself a little bit more might be in keeping with the thrust of the program".

(Transcript Volume 13, page 3082)

In his pre-filed testimony (page 17) GWC stated,

> "A second matter of concern relates to non-utility generation or NUG's. Table 2.1 of Appendix XVII indicates a customer self generation or NUG contribution of 25 GWH to the overall target of 500 GWH. This represents only 5% of the total target....one would expect that the opportunity for reductions in the load to be served through co-generation and self generation by industry would be for greater than indicated. This target appears to be unrealistically low."

WRA

In their pre-testimony, WRA stated,

> "This area of Manitoba Hydro's presentation seems to have received less than the attention it warrants. Clearly this aspect of utility planning is new to the provinces' crown corporation.
>
> .... the presentation discloses a degree of uncertainty absent from the program to export energy.
>
> The approach adapted relies principally on conservation ...."
>
> "DSM initiatives outlined in its filing appear to give most weight to energy conservation. Only cursory attention is given to load shifting and load management alternatives. Load management alternatives have a desired effect of reducing peak load and shifting on-peak load to off-peak periods, thus reducing capacity requirements and increasing the ability to make high value on-peak sales.

(Transcript Volume 8, page 1692)

> "It is our view that Manitoba Hydro's DSM target is substantially understated. DSM targets could well be in the 400 to 500 MW range by the year 2000 if Manitoba Hydro pursued DSM aggressively. This would allow additional firm sales, for example, to Ontario Hydro."

(WRA Pre-filed Testimony, pages 62 and 63)

Manitoba Hydro witness Dr. Chamberlin stated,

> "... my feeling is that with aggressive programs, it's probably possible for Manitoba Hydro to achieve something, perhaps as much as 4% or 5%. It is possible that amounts less than the 2% are all that can be achieved, I don't know, and I don't think that anybody does."

(Transcript, Volume 3, page 624)

The targets that CSC, CAC, WRA and GWC have suggested using are based on information obtained from Ontario Hydro, B.C. Hydro, and other utilities predominantly in the U.S. all operating under different circumstances than Manitoba Hydro. The U.S. utilities generally experience their greatest loss and highest demand on their systems in the summer compared with the Manitoba peak in the winter.

MIPUG

MIPUG has stated,

> "The available economic evidence does not allow the Board to determine a least cost plan for DSM at this time; this situation, however, would not be adversely affected by the Ontario Sale, i.e., it reflects other considerations related to the very early stages of Manitoba Hydro's DSM planning. As noted earlier, the Ontario sale would also not adversely effect the aggressive pursuit of DSM by Manitoba Hydro....The balance of evidence indicates that the Ontario sale is not in conflict with the pursuit of aggressive DSM by Manitoba Hydro."

(Written Argument, page 9)

> "Future DSM programs must yield sufficient anticipated benefits to cover program costs".

(Written Argument, page 10)

> "Based on the available evidence, it would not appear prudent at this time to proceed on the assumption that a significant expansion program of the DSM target should be adopted or that significant modifications should be made to the dependable energy planning criteria to enable less stringent protection of consumers. Similarly, given the existing reliance on imports to meet dependable energy requirements, the option of considering additional import purchases does not appear to be attractive. In fact, there may be some basis for concern that Manitoba Hydro is relying too extensively upon non-firm import supplies....which provides a list of all utilities with interconnection facilities with Manitoba Hydro and the projected surplus in utilities for each year from 1990 to 1999)."

(Pre-filed Testimony, page 22)

MIPUG recommended that the Board not endorse at this time, the use by Manitoba Hydro of special 'bonus' criteria (10% adder) for DSM; instead, they would recommend that Manitoba Hydro be required to assess all DSM programs in light of all relevant considerations. Domestic customers are interested in ensuring least cost rates with respect to all aspects of Manitoba Hydro planning, including DSM.

NFC

NFC stated that,

> "Manitoba Hydro possibly can be criticized for having not made a commitment to a DSM project earlier but the fact remains that all of the experts who testified agreed that today a DSM program in Manitoba will take some time to develop and implement."...."The NFC accepts that the 100 MW of DSM assumed by Manitoba Hydro in system planning to the year 2000 is reasonable under the circumstances."

(Written Argument, pages 9, 10 and 15)

Manitoba Hydro's witness, Dr. Chamberlin, says:

> "It's important to differentiate between reductions in summer peak and reductions in annual energy in 2000, and the reason I am saying that is there is substantially greater reductions and forecast reductions in summer peak than there is in annual energy. That's primarily in my opinion because reduction in summer peaks are easier to get and cheaper."

(Transcript, Volume 3, pages 587 and 588)

> "I think the appropriate target isn't a megawatt or a megawatt hour, it's a criteria. I believe that criteria to be cost effectiveness and I believe that Manitoba Hydro or any utility ought to implement those programs which are cost effective".

(Transcript, Volume 3, page 623)

Manitoba Hydro, in their final argument, state,

> "Manitoba Hydro is pursuing DSM to its fullest cost effective extent, but no rigorous evidence as to the extent of DSM potential in Manitoba is available."

(Written argument, page 20)

Board Findings

The CSC evidence included a critique of Manitoba Hydro's plans to achieve 100 MW DSM by 2001. Their evidence convinced the Board that Manitoba Hydro's target may be represented as the efforts of a utility, which though undeniably highly competent and expert in conventional generation, is at the initial stage of the learning curve in regards to DSM.

This point is extraordinarily important in considering CSC's evidence regarding the modest level of Hydro's target for DSM compared to those utilities cited by CSC as examples of what could be achieved. These were represented as being in the 7%-15% range in contrast to Manitoba Hydro's 2.2%.

It is difficult to argue, as CSC did at great length in Appendix F of its pre-filed testimony, that Manitoba Hydro's 100 MW target shows evidence of many omissions and at the same time argue that the same organization has the capability to achieve the same high targets apparently achievable by utilities who, in CSC's view, are representative of advanced thinking in this matter.

It was also stated that BC Hydro, which has a higher DSM target, took 3 years to move from a standing start to offering large-scale programs to all customers. In addition, the Board notes Dr. Chamberlin's remarks in regard to the characteristic learning period needed to reach a high level of expertise for DSM.

The net effect of these remarks is to bring the Board to the conclusion that CSC's criticism of Manitoba Hydro's present competence in this area is to cast doubt upon CSC's other assurances that 500 MW DSM can be reached to safely defer Conawapa to the far distant future.

The Board sees that there are clear signs from this hearing that Manitoba Hydro is on the march to competency in DSM. The most significant sign was the strong and vigorous statement made by Mr. Ransom regarding Manitoba Hydro's management commitment to DSM.

The accumulation of CSC's capable attack on Manitoba Hydro's present competence in DSM combined with other evidence of the Utility's early stage of development leads to the conclusion that to recommend that any generation source required by 2000 be delayed solely on the risky possibility of Hydro being able to "ramp-up" its DSM would be unwise. The Board therefore concludes that 100 MW is an appropriate DSM target to use for generation planning purposes.

A distinction must be made between a DSM target in the sense of an objective and a figure to be used for planning purposes. The Board completely supports the principle that the economic potential of DSM should be fully exploited to the extent that such DSM programs are cost-effective. The Board believes that Manitoba Hydro should set its sites high. The full implementation by Manitoba Hydro of DSM will require a detailed knowledge of the best practices used by other utilities. Adaptation of this practice to the particular characteristics of Manitoba Hydro will require vigorous continuation of Manitoba Hydro's present commitment to DSM.

On the subject of DSM and the regulation process, the Board notes that Demand-Side Management is an economics driven process which potentially benefits all Manitoba consumers. These benefits accrue because DSM can delay required additional generation, transmission, and distribution facilities as well as reduce operating, overhead and maintenance costs. All consumers benefit from the lower revenue required by Manitoba Hydro.

The effect of DSM expenditures on rates is a matter of interest to the Board because of its statutory responsibilities. DSM expenditures which exceed the difference between avoided cost and average embedded cost would increase rates with the potential for inequity between customers or customer classes. In consequence, Manitoba Hydro may find that considerations of equity will limit its achievable DSM. The matter of DSM, particularly as it effects rates, will be reviewed by the Board from time to time at future rate hearings.

The Board recommends the elimination of the 10% premium which is currently added by Manitoba Hydro to its avoided costs to assist the viability of each program. The DSM programs should be adequate to support an expenditure without this type of assistance.

Supply Options

The electrical load on the Manitoba Hydro System has increased in the past and will continue to increase in the future according to current load forecasts. To accommodate this increase and comply with its mandate, Manitoba Hydro must establish new sources of generation. Manitoba Hydro must do something; doing nothing will result in power shortages and brown-outs.

According to the 1990 Load Forecast, Manitoba Hydro will be unable to supply their customers' demand needs by 1997 and their energy needs by 1996 if no action is taken.

Manitoba Hydro has submitted that there is a wide range of supply options available. These options include: additional hydraulic or thermal generation; thermal plant life assurance; non-utility generation; life extension of existing plants; import/export transactions.

Hydraulic and Thermal Plant Additions

The most economic options, according to Manitoba Hydro, are major new hydraulic plant additions on the Nelson and Burntwood Rivers. A comparison has been prepared by Manitoba Hydro illustrating the average plant costs in cents/kW.h, with all plants having a hypothetical 1999 in-service date, as indicated below.

The average plant costs were determined by levelizing the expected in-service costs over the life of the plant, and dividing by the expected average annual energy capability.

Comparison of Major Potential Hydraulic Sites

Name	Capacity* MW	Average Energy* GW.h/Year	Relative Energy Cost** Cents/kW.h
Nelson River			
Conawapa	1290	7045	5.7
Gillam Island	850	4980	7.8
Gull ***	535	2900	6.7
Birthday	540	3265	6.4
Whitemud	310	1700	9.6
Red Rock	190	1160	12.1
Kelsey Ext.	220	705	12.7
Burntwood River			
Wuskwatim	350	2200	5.4
Manasan	215	1670	9.7
First Rapids	250	1400	7.9
Notigi	110	780	8.4

* Figures are approximate only, final developments will probably differ. Figures also include adjustments, when necessary, to recognize losses at upstream plants caused by the creation of the forebay at the added plant.

** Generation costs only; transmission costs not included.

*** The Gull and Birthday capabilities shown assume full development of the potential head in that reach of the Nelson River. While this is technically feasible, other considerations may constrain the Birthday site to a capability lower than shown.

- The sequences of development shown in the section entitled 'Alternative Scenarios' show development of the Birthday site. The above tabulation indicates that development of Gull instead would provide approximately the same capability at approximately the same cost. The indication of Birthday development in the sequences thus represents development at either Birthday or Gull.

The locations of these major hydraulic supply options are shown on the map in Appendix VIII.

Each hydro-electric supply option has specific transmission requirements.

Manitoba Hydro has stated that the Nelson River plants will require high capacity transmission lines to carry the large amounts of power generated. Conawapa will require a third HVDC transmission line (Bipole III) to the Winnipeg area. Subsequent Nelson River plants will require additional development of Bipole III, and will ultimately require additional transmission as well as Bipole III.

New hydro stations on the Burntwood River are about one third or one quarter the size of Nelson River plants and would require transmission that is correspondingly smaller. The transmission for the Wuskwatim generating station option consists of an expansion of the existing 230 kV system from Thompson to Flin Flon, and new transmission from Thompson to Grand Rapids.

Other generation, such as coal-fired thermal plants, gas turbines, nuclear plants, solar and wind options are by Manitoba Hydro's calculations, more expensive per kW, and/or less environmentally acceptable alternatives when compared with the hydraulic options. Cost comparisons (also for a hypothetical 1999 in-service date) are as follows:

Comparison of Potential Non-Hydraulic Options

Name	**Capacity MW**	**Average Energy GW.h/Year**	**Relative Energy Cost Cents/kW.h**
Coal-Fired *	400	2,250	15.0
Combustion Turbine *	200	350	45.4
Nuclear *	3,500	24,700	14.4
Solar/Wind			25 to 30

* The costs are based on the coal fired and nuclear plants operating continuously as base load plants. For economical operation these plants are assumed to be fully loaded for 65% and 80% of the time respectively. The combustion turbine would be a peaking plant and operate fully loaded 20% of the time.

The above cost information comparison is used by Manitoba Hydro to assess which options are worthy of more detailed study. Selection of the preferred next addition is based on more detailed study (described in the sections entitled, "Manitoba Hydro Alternative Supply Scenarios" and "Evaluation of Key Scenarios") and not merely on comparison of the costs shown.

New coal-fired plants and combustion turbines would be installed in the southern Manitoba system near sources of cooling water and as close as possible to the fuel supply. These plants would feed into the existing transmission system and would probably not require major transmission system additions.

Conawapa and Wuskwatim are the lowest cost hydraulic plant alternatives, so Manitoba Hydro has been concentrating efforts over the past few years on improving design and cost estimate information on these two options to evaluate them as competitors for the next supply addition.

Combustion turbines and coal-fired thermal plants are also considered by Manitoba Hydro in evaluations to complement, or compete with, the hydraulic options.

Thermal Plant Life Assurance

Manitoba Hydro has advised that the thermal plants at Brandon and Selkirk have a total capability of 369 MW. Most of the units were installed in the late 1950's and early 1960's, and will be about 40 years old by the turn of the century. Thermal plants are normally expected to last for about 35 years.

The Brandon and Selkirk plants are used primarily to provide energy for Manitoba loads during droughts. They are run extensively about one year in eight, to supplement river flows during low water conditions. The Brandon plant is also run over the peak load winter months to support the Winnipeg-Brandon transmission lines.

Retirement of the thermal plants will influence the timing and selection of transmission construction and of the next generating plant needed to meet load growth and Manitoba Hydro commitments. After study of the physical condition of the plants and the implications on future system plans and operation, Manitoba Hydro concluded that some work was required to ensure that the plants will last until their predicted retirement dates.

The coal-handling facilities at the plants, according to Manitoba Hydro, will be modernized to accommodate the efficient handling of coal and changing transportation requirements. Equipment to reduce discharge of waste will also be added to meet more stringent environmental requirements in accordance with the Manitoba Environment Act. Electrostatic precipitators at Brandon and Selkirk will reduce particle emissions in the smoke and a cooling tower at Brandon will reduce water temperatures. Refurbishment of boilers and related equipment is also required.

The estimated costs of life-assuring the Brandon and Selkirk plants are $56 million and $43 million, respectively.

The extension of the life of these thermal generating stations beyond their expected life is a possible option. Manitoba Hydro claims this cannot be truly assessed until these generating stations have reached their rated life. Their condition can then be evaluated and upgrading costs determined so their life extension possibilities can be examined against other options.

The option of life extension of existing plants would generally require no new transmission unless an increase of the plant output is part of the life extension program. In some instances, refurbishment of aging transmission and station equipment could be necessary.

Regarding the possibility of life extension, Manitoba Hydro has indicated:

> "Any assumption today that the Brandon and Selkirk thermal plants can be absolutely counted on beyond their currently scheduled retirement dates is considered to be speculative -- the plants are simply too old and require major rehabilitation to get even that far. However, all steps now being undertaken do not preclude such extension should it later be confirmed to be feasible."

("Risk Management and Exposures", Exhibit #MH-3A, page 25)

In the Benefit-Cost and Economic Impact Analysis of Manitoba Hydro's Preferred and Alternative Generation Expansion Plans, prepared by Marvin Shaffer & Associates Ltd., the issue of thermal versus hydraulic generation is discussed:

> "In expansion plans #5 and #7, a 200 MW thermal (coal) generating station project is included among the hydraulic generating projects. The inclusion of a thermal generating station implicitly suggest a substitution for hydraulic generation; consequently a comparison of the potential environmental concerns could be important in the choice between generation expansion plans.
>
> In plan #5, the First Rapids Project is replaced by a Thermal Project. The potential effects of a thermal generating project are very different from those of hydraulic generation stations. The proposed in-service dates for thermal projects would permit locating the new plant at an existing site (likely Brandon), consequently a new transmission line may not be required. Gaseous emissions of SO_2 and NOx present concerns regarding air quality and acid rain which can be partially mitigated using low sulphur coal and burner technology to reduce emissions. Airborne particulate can be substantially reduced by the use of electrostatic precipitators. Ash disposal and warm processed water treatment present environmental concerns which can be mitigated by the use of clay-lined ash pits and water cooling towers. In addition to these local concerns, the production of "greenhouse gases" presents a concern about global climatic changes.
>
> The potential impacts of the First Rapids project are quite different. Flooding associated with the generating station raises notable environmental concerns regarding mercury methylation, disruption of trapping and effects on infrastructure in Thompson. New transmission lines (over 600 km) raise environmental concerns related to the effects of electric and magnetic fields on human health and the visual intrusion of the new lines.
>
> Without better information and an accepted method for evaluating the relative significance of these potential environmental effects, a descriptive comparison of thermal and hydraulic generation concerns presents no clear direction."

(Manitoba Hydro Submission, Appendix XIV, pages 11 and 13)

Non-Utility Generation

As previously noted, non-utility generation (NUG) falls into two broad categories:

1) Customer Generation. In this category, a customer can provide part of his own requirements but is still a net purchaser from the utility.

2) Independent Power Production (IPP). In this second category, the generator is a net seller of electricity to the utility.

Current and anticipated future Customer Generation is excluded both from the system load forecast and as a supply option. The potential for customers to reduce present purchases by self-generation is considered as a DSM option.

Power purchases from IPPs are considered as a potential supply option, and are evaluated on an individual basis as proposals evolve.

The Independent Power Production type of generation will consist of relatively small plants which may or may not be located adjacent to existing portions of the distribution system. If they are, changes to the existing system will be required, if not additional transmission facilities will have to be added. This transmission would probably not be long and the load they would be required to carry relatively small so their cost would likely not be excessive.

Rehabilitation, Efficiency Improvements and Life of Existing Plant

Hydraulic Plants

All hydraulic plants currently in existence are expected to remain in service for at least another 40 years. Retirement of existing hydraulic plants is therefore not a factor in the selection of the next generation addition. There are also possibilities of replacing the turbines at some of the existing hydraulic plants to achieve greater output. Most of these projects, when examined individually, do not provide sufficient increased capability to affect the timing of future generation additions. The addition of turbines and generators at the existing Kelsey plant and the Notigi Dam are future options, but more expensive than others as yet. However, taken together they can affect future plans.

Thermal Plants

Existing thermal plant life options range from immediate retirement to life extension to beyond 2010. The life of the thermal plants would affect the timing and selection of the next generating plant. The life assurance program which Manitoba Hydro is undertaking will ensure that the plants will operate in a reliable manner until the end of their rated lives.

Import/Exchange Transactions

Committed imports and exchanges with neighbouring utilities are considered part of Manitoba Hydro's supply and demand. Potential new imports or exchanges are developed through Manitoba Hydro's constant review of situations that may arise in Manitoba and neighbouring jurisdictions. With the commitments contained in Manitoba Hydro's Preferred Development Plan, there is a limited amount of diversity remaining for future exchanges until the end of the existing contracts, thereby reducing possible opportunities in the nearer term. An opportunity which may be identified and developed does not necessarily result in a contract. The process of identification, evaluation, and negotiation must result in benefits to all parties before an agreement can be reached. Manitoba Hydro has not identified any additional major transactions, but remains aware of the neighbouring utilities' needs and plans through ongoing discussion. As opportunities arise, the negotiation of new contracts will depend on the benefits to Manitoba Hydro. The sale of surplus power will continue, utilizing transmission presently in place, as will the import of power to help offset shortages and more expensive environmental damaging thermal generation.

Imports and diversity exchanges, if large enough, may require new transmission. The NSP/UPA 300 MW diversity agreement, which is included in Manitoba Hydro's Preferred Development Plan, will require reinforcement of the interconnections between Manitoba and the U.S. consisting of upgrading the existing tie lines, alone or in combination with the construction of a new transmission line between Manitoba and Minnesota.

Position of Independent Witnesses and Intervenors

CSC

On page 140 of their Pre-Filed Testimony CSC stated:

> "Manitoba Hydro has failed to adequately consider alternative supply resources to construction of new dams, including hydro repowering, new generation at existing dams, firming non-firm energy, and private power resources".

CSC claims that consideration was not given to additional generation at Kelsey or generation at Notigi when Manitoba Hydro prepared alternative generation sequences. They claim that Kelsey is only 12% more costly on a per unit basis than Conawapa and that Notigi, not including transmission, is 20% less costly than Conawapa. They also suggest that there will be little impact on the Notigi cost due to the transmission because of the "project's small size".

Manitoba Hydro demonstrated in response to an interrogatory (PUB) MH(11) 59) that Kelsey would cost, not including transmission, over twice as much as Conawapa and is 43% higher than Conawapa if its transmission is included. CSC subsequently acknowledged its error. Manitoba Hydro stated in its rebuttal evidence that significant new transmission is required for Notigi and that the total unit cost is higher than Conawapa and Wuskwatim. This plant was not considered in the sequence evaluation, according to Manitoba Hydro, because of its size (110 MW). A small plant if developed now would result in additional generation being required within a year or so and as a result, larger plants were included in the sequence evaluation. Manitoba Hydro stated that they will continue to consider Kelsey and Notigi in future studies.

On page 31 of their final argument CSC stated:

> "Since Manitoba Hydro does not have to add any major hydro-electric plant to its system until at least 2006, there are a number of years available for Manitoba Hydro to determine the potential of NUG power. CSC recommends that any decision to add or forego the next major hydro-electric supply option should include a full review of NUG potential".

GWC

GWC, in pre-filed testimony, suggested that Manitoba Hydro has not formulated a "comprehensive supply side management program plan".

Manitoba Hydro acknowledged that they did not have an all encompassing document but do carry out routine studies to optimize the supply efficiency. They gave as examples; Winnipeg River plant updates and improvements which increase their output, rerunnering studies at Kettle, and implementation at Kelsey, routine consideration of the possibilities of loss reduction in the transmission and distribution system.

GWC in pre-filed testimony, stated on page 18:

> "Manitoba Hydro places emphasis on the undeveloped potential of hydroelectric sites on the Nelson and Burntwood Rivers when it considers future supply options. In general support of its thrust, Manitoba Hydro compares . . . the cost of energy from the various hydraulic sites to the costs associated with certain non-hydraulic supply options and quickly dismisses all non-hydraulic supply options. While its conclusions may be correct, it has not proved its case well. Little attention has been given to large, base loaded combustion turbines fuelled by natural gas and operating either in simple or combined cycle modes."

WRA

WRA indicated in pre-trial testimony (page 57) that,

> "Manitoba Hydro's submittal has given relatively superficial treatment to the potential for non-utility generation, independent power producers and interruptible loads to lower costs to provincial retail customers."

CAC/MSOS

CAC/MSOS (page 70 of its final argument) stated,

> "If the NUG capacity of Northern Ontario (which has terrain similar to Northern Manitoba) is any indication, there should be at least a few hundred MW of small scale hydro power available in Manitoba that can be carried by the Limestone transmission line. Ideally, such projects could be built by native groups. With initial advice from the Independent Power Producers Society of Ontario, a trade association which now has in place or has proposed some 138 NUG projects for a total of 8,213 MW. It may be desirable for Manitoba Hydro to agree, initially, to pay something more than its avoided cost in order to compensate for the provincial subsidies it receives to provide some initial assistance to a fledgling industry.

Manitoba Hydro has responded to these concerns by stating that it has a corporate policy of purchasing power from NUG's up to the avoided cost and has undertaken discussions and studies with several candidates.

MIPUG

MIPUG, on pages 5, 10 and 25 of its pre-filed testimony, stated:

> "The proposed hydraulic development in northern Manitoba should be viewed in the context of long term planning commitments and investments by Manitoba Hydro and the Province in the 1960's and 1970's and the evidence that this approach remains considerably less costly than development of comparable thermal generation, e.g., coal thermal would involve costs some 40 per cent above the proposed hydraulic option. Regardless of the Ontario Hydro sale, Manitoba Hydro likely needs two new generating plants and Bipole III sometime prior to the 2015 - 2020 time period unless DSM achieves five times or more present target."

In answer to criticisms that it had not given adequate consideration to additional firming strategies as opposed to new hydraulic plants Manitoba Hydro has outlined in its rebuttal evidence what it considers to be firming strategies, including:

1) Contribution of the hydraulic reservoir storage capacity.

2) Consideration of gas turbine generation to make up for energy or capacity shortfall in their sequence analysis.

3) Use of existing coal burning thermal stations.

4) Deferred energy component of the proposed 1000 MW sale to Ontario.

5) Associated energy guarantees from diversity exchange contracts.

6) Energy guarantees associated with the firm power sales contracts.

Board Findings

The Board acknowledges the useful purposes of thermal plants in firming power, peaking power, and system reliability and endorses the work necessary by Manitoba Hydro to ensure that the existing plants in Brandon and in Selkirk can be relied upon for the remainder of their rated life (life assurance program). Once these plants have reached their rated life, they should be evaluated for further service. If it is deemed feasible at that time, the plants, or some units in the plants, should be examined, renovated and updated as necessary and kept in operation as long as economically reasonable (life extension program). The environmental concerns relating to thermal generation plants are acknowledged by the Board. The Board is also aware that the possibilities of future generation of this type may be restricted or completely prohibited which further supports the Board's belief that continuation of existing plants as long as possible is advantageous.

The Board recommends that no new base load thermal plants should be considered due to their long term costs when compared with hydro-electric plants and also due to their effect on the environment.

The Board encourages Manitoba Hydro to continue active negotiations with neighbouring utilities to enhance their import/export and diversity agreements whenever possible and economical.

Non-utility generation (NUG) is endorsed by the Board. The Board recommends Manitoba Hydro pursue this supply option.

Regarding the assertion by CSC and other intervenors that Manitoba Hydro has failed to give sufficient consideration to non-utility generation, the Board notes that Manitoba Hydro does offer to purchase electricity at avoided cost. However, relatively low Manitoba Hydro rates and the relatively small number of industrial customers are circumstances which tend to limit the potential in Manitoba. The Board concludes that under the circumstances, it is appropriate to exclude NUG potential for planning purposes.

The Board accepts Manitoba Hydro's outline of hydro-electric supply options as being reasonable and appropriate for planning purposes.

Manitoba Hydro's Alternative Supply Scenarios

In previous sections of this report, the Board reviewed Manitoba Hydro's load forecast as well as the various options available to meet the forecasted load. This section examines the specific plans by Manitoba Hydro, utilizing options that are available to meet the forecasted load.

By virtue of paragraph 1 (d) (iii) of Order in Council No. 177/90, the Board is to review and consider whether all reasonable alternative options have been considered.

During the hearing, the Board reviewed the various alternative scenarios for generation and transmission during the period 1990 to 2009 as presented by Manitoba Hydro and the intervenors.

The alternative supply scenarios that were advanced by Manitoba Hydro were:

1) Manitoba Hydro's Preferred Development Plan (Preferred Scenario).

   On the basis of its current load forecasts, Manitoba Hydro anticipates that generating capacity in Manitoba will be fully utilized by the year 2000, and therefore new resources will be needed by that time. Manitoba Hydro, in putting forward its Preferred Development Plan, stated that it offers the best way to meet the future needs for electricity.

   Manitoba Hydro's Preferred Development Plan includes four initiatives:

   a) The 1000 MW Ontario Hydro sale.

   b) The 150 MW NSP and the 150 MW UPA Diversity exchanges.

   c) The thermal generating station life assurance program.

   d) The 100 MW demand-side management target by the year 2001.

   If any of the four initiatives were cancelled or withdrawn for any reason, a different scenario would result which would require a different plan of development. The other six scenarios put forward by Manitoba Hydro for consideration by the Board involve variations on the four initiatives contained in Manitoba Hydro's Preferred Development Plan.

2) Preferred scenario without the Ontario 1,000 MW Sale.

3) Preferred scenario without the NSP/UPA diversity exchange.

4) Preferred scenario without the Ontario Sale or the NSP/UPA diversity exchange and with Conawapa assumed to be the next plant.

5) Preferred scenario without the Ontario Sale or the NSP/UPA diversity exchange and with Wuskwatim assumed to be the next plant.

6) Preferred scenario without thermal life assurance.

7) Preferred scenario without the demand-side management program.

Scenario 1 - Manitoba Hydro's Preferred Development Plan

Under this scenario, the development sequence is:

Plant	In-Service Year
Conawapa	2000
Wuskwatim	2007
Birthday/Gull	2011
Manasan	2014
First Rapids	2015

According to Manitoba Hydro, a commitment to Conawapa for 2000 in-service will be required in late 1990. Under the Preferred Development Plan the sequence of development after Conawapa would not be committed and the selection and timing of future plants would be the subject of continuing studies by Manitoba Hydro. Wuskwatim is one of the options which would be considered for 2007. The timing of the next generation plant after Conawapa is dependent on the life of the existing thermal plants. The 2007 date is based on the assumption that the thermal plants will retire on their currently planned dates. Decisions on life extension will be made in conjunction with the selection of the next new generating plant following Conawapa.

Scenario 2 - Preferred Scenario Without the Ontario Sale

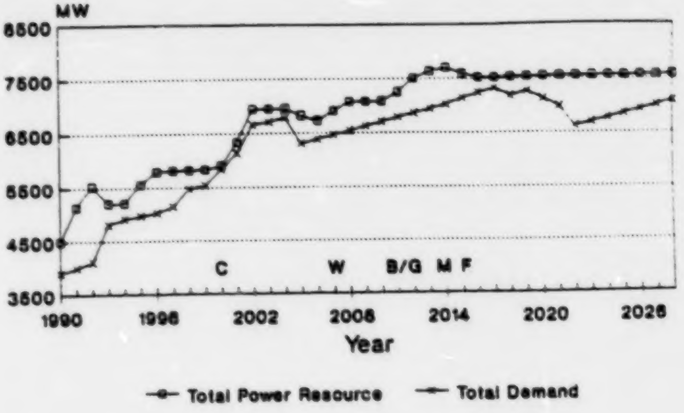
Under this scenario, the development sequence is:

Plant	In-Service Year
Wuskwatim	2002
Conawapa	2010
Birthday	2017
Manasan	2023
First Rapids	2027

Manitoba Hydro contends that Wuskwatim in 2002 provides sufficient generating capability until 2010. Conawapa, in 2002, on the other hand, would provide sufficient capability until 2015. Under this scenario, Wuskwatim in 2002 is selected by Manitoba Hydro as the next plant since long-term economic evaluations show that this sequence is less costly than the Conawapa-first sequence by approximately $230 million (1989 $). Without the Ontario sale, a decision on Wuskwatim versus Conawapa would have to be made by the Fall of 1992.

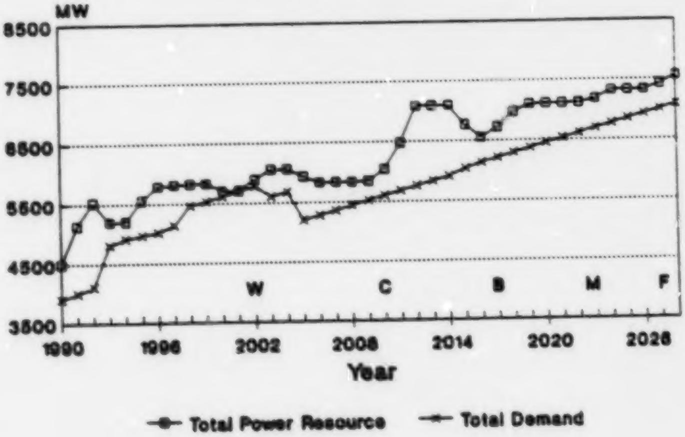
The following figures illustrate system capacity and energy demand and resources pursuant to the planned development sequences for Scenarios 1 and 2. The figures demonstrate that with Scenario 1, supply matches demand more closely and thus, Scenario 1 generates much less surplus than Scenario 2.

System Capacity Demand and Resources
Scenario 1 - Manitoba Hydro's Preferred Development Plan



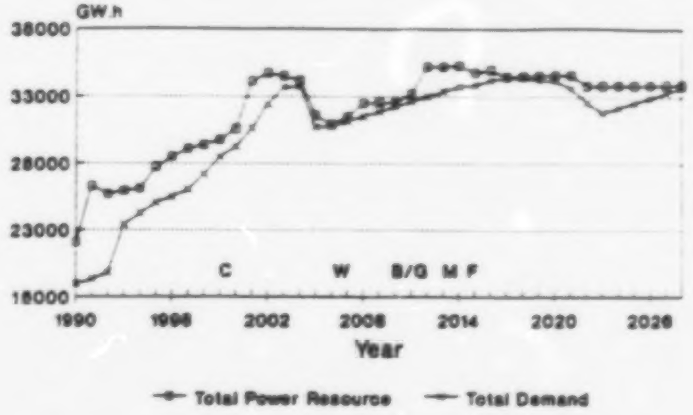
Source: MH Submission - Table 7-1

System Capacity Demand and Resources
Scenario 2 - Diversity, No Ontario Sale



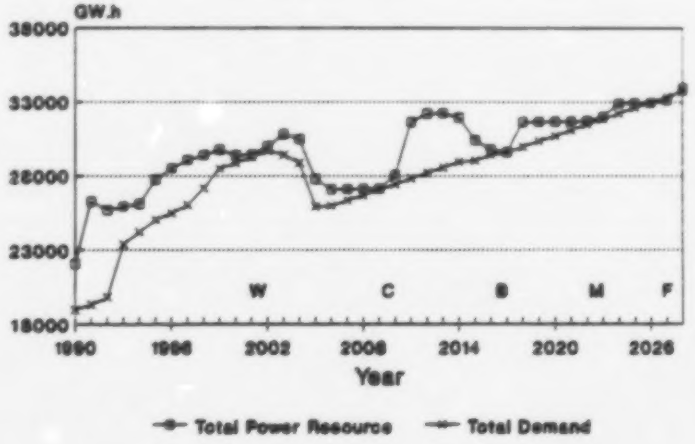
Source: MH Submission - Table 7-6

System Energy Demand and Resources
Scenario 1 - Manitoba Hydro's Preferred Development Plan



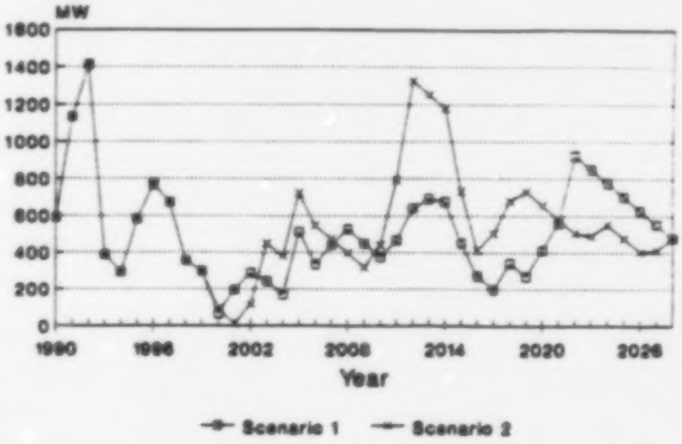
Source: MH Submission - Table 7-2

System Energy Demand and Resources
Scenario 2 - Diversity, No Ontario Sale



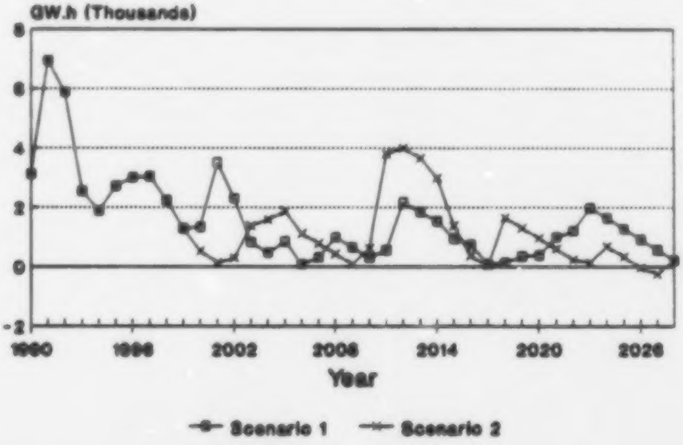
Source: MH Submission - Table 7-6

Surplus Capacity
Scenario 1 and Scenario 2



Source: MH Submission - Tables 7-1/7-6

Surplus Energy
Scenario 1 and Scenario 2



Source: MH Submission - Tables 7-2/7-6

Scenario 3 - Preferred Scenario Without the NSP/UPA Diversity Exchange

Under this scenario, the development sequence is:

Plant	In-Service Year
Conawapa	1999
Wuskwatim	2002
Birthday	2007
Manasan	2014
First Rapids	2015

Manitoba Hydro submits that with current load forecasts, the 1999 requirement for additional supply would have to be addressed given that the current Conawapa schedule would result in a 2000 in-service date. Deficits approximately equal to one year of load growth would occur in 1999 and 2000 with Conawapa in 2000. Options for dealing with the predicted deficits under this scenario include:

1) Acceleration of Conawapa's construction.

2) Purchases from neighbouring utilities.

3) Installation of gas turbines which would have a short lead time.

Scenarios 4 and 5 - Preferred Scenario Without the Ontario Sale or the NSP/UPA Diversity Exchange

Under these two scenarios, either Conawapa or Wuskwatim would be required in 1999. The development sequences would therefore be:

Conawapa First		Wuskwatim First	
Plant	In-Service Year	Plant	In-Service Year
Conawapa	1999	Wuskwatim	1999
Wuskwatim	2015	Coal (200MW)	2001
Birthday	2017	Conawapa	2009
Manasan	2023	Birthday	2020
First Rapids	2027	Manasan	2027

By adding Conawapa in 1999, no additional generation would be required until 2015. Alternatively, by adding Wuskwatim in 1999, additional generation would be required in 2001. A decision was not made by Manitoba Hydro on which alternative would have been selected if the sale and diversity had not been negotiated. Both sequences are shown for comparative purposes.

Scenario 6 - Preferred Scenario Without Thermal Life Assurance

Under this scenario, the development sequence is:

Plant	In-Service Year
Conawapa	1999
Wuskwatim	2002
Birthday/Gull	2011
Manasan	2014
First Rapids	2015

Without thermal life assurance, the thermal plants at Brandon and Selkirk will be retired early and this would advance Conawapa from 2000 to 1999. Wuskwatim would be advanced from 2007 to 2002. Other plant timing would not be affected since all thermal plants are assumed to be retired by 2006.

Scenario 7 - Preferred Scenario Without the Demand-Side Management Program

Under this scenario, the development sequence is:

Plant	In-Service Year
Conawapa	2000
Wuskwatim	2004
Birthday	2010
Manasan	2014
First Rapids	2016
Coal (200MW)	2016

Without the DSM targets, the load to be supplied by 2001 would be approximately 100 MW greater. Conawapa would remain at 2000 but subsequent plant timings would be affected.

Position of Independent Witnesses and Intervenors

Various intervenors and the independent witnesses commented on Manitoba Hydro's choice of scenarios put forward for review.

GWC

GWC had the following observations to make regarding Manitoba Hydro's alternative scenarios:

> "Manitoba Hydro has examined a number of different expansion sequences each of which reflects the affect of various assumptions regarding firm power sales, demand side management, extension of the lives of thermal plants, and diversity exchanges. The one common link amongst all the sequences is that each one is based on the development of northern hydroelectric generation with the only variation being the ordering and timing of the construction of new hydroelectric facilities. Regardless of the scenario or sequence considered, all of the hydraulic sites on the Nelson and Burntwood Rivers are eventually developed, at least in theory.
>
> In my view, Manitoba Hydro has not demonstrated that this single-minded approach to generation development represents the best course of action for the ratepayers. Scenarios and associated sequences of generation which satisfy only the provincial demand for electricity and which do not depend exclusively on the continued development of the northern river systems have not been presented."

(GWC, Pre-filed Testimony, page 21)

WRA

WRA was concerned that individual load forecasts were not prepared for each of Manitoba Hydro's alternatives and recommended that price-elasticity effects be examined:

> ". . . Manitoba Hydro has not reflected different relative prices of electricity to gas for different sequences by developing sequence-specific load forecasts for each sequence. Manitoba Hydro's position appears to be that price elasticity effects would not change the relative ranking of various sequences . . .
>
> To ascertain that the load forecast would not be substantially different under different sequences, Manitoba Hydro should develop sequence-specific load forecasts for the seven sequences. If it is found that the sequence-specific load forecasts are not substantially different, one can conclude that price elasticity effects would be insignificant."

(WRA, Pre-filed Testimony, pages 67-68)

Manitoba Hydro noted WRA's argument that electricity prices should be calculated for each scenario which would presumably lead to a new sequence optimization and new rates scenarios, resulting in a second load forecast, and so on, until convergence is achieved. Manitoba Hydro's response indicated that theoretically this is true, but in practice, it is impossible:

> ". . . each cycle takes about six months to perform properly, so it is unlikely convergence would ever be achieved prior to the next annual cycle having to commence. An approximation is achieved by using the results of each year's Integrated Financial Forecast in the next year's Economic Outlook and Load Forecast.
>
> In any event, the potential problems cited by WRA (page 67) are considered to be over-stated. . . . the projected cumulative rates associated with the five most competitive scenarios will be within +9%, -2% of the preferred scenario, well below the extreme 25% cited. While these differentials would have some impact on forecast market shares, they are considered to be of only minor significance in light of all the other uncertainties involved."

(Manitoba Hydro, Rebuttal Evidence, pages 69-70)

The Board, as noted in the previous section entitled, "Load Forecast", has accepted Manitoba Hydro's load forecast as the basis for generation planning.

The positions of CAC/MSOS, CSC and MIPUG are examined collectively below.

CAC/MSOS

In his opening remarks, counsel for CAC/MSOS was critical of the alternative scenarios put forward by Manitoba Hydro for comparison with its Preferred Development Plan.

> "Manitoba Hydro's Submission used the classic bureaucratic way of appearing to look at alternatives without really doing so. The preferred plan is presented beautifully gift wrapped with promises of large profits and low rates while risks and costs are understated or ignored. On the other hand, to create the illusion that meaningful alternatives have been examined, other scenarios are concocted containing less favourable and improbable courses of conduct. Inevitably, this slanted presentation would lead the uncritical reader to the conclusion that the preferred plan is the best one.
>
> As our evidence and argument will show, the only meaningful options discussed by Manitoba Hydro are its preferred development plan and the same plan without the Ontario Hydro sale. To date, Manitoba Hydro's evidence is insufficiently thorough even to show which of those options is better."

(Transcript, Volume 1, page 37)

In its closing argument, CAC/MSOS concluded on Manitoba Hydro's alternative supply scenarios as follows:

> "Of the seven scenarios discussed in part 7.0 of the Submission, six are presented as alternatives to the preferred scenario. Only one of these, Scenario 2, is a real alternative, but that has not been shown on a least cost basis. 'Alternative' scenarios without the NSP/UPA diversity exchange, thermal life assurance, or a demand-side management program are non-starters and should not even have been alternatives."

(CAC/MSOS, Written Argument, pages 8-9)

CSC

On Manitoba Hydro's proposed alternative scenarios, CSC concludes:

> "Of the original 7 scenarios, most were straw men: they would never have been selected and primarily served the purpose of making Manitoba Hydro's preferred scenario look good."

(CSC, Written Argument, page 33)

MIPUG

MIPUG concluded that all relevant sequence options have been presented and that Wuskwatim and Conawapa should be examined as the two most obvious contenders:

> "MIPUG also submits that expert evidence has confirmed the appropriateness of using sequence methodology, including economic evaluations which compare the costs and benefits associated with the sequence of expansion of one scenario with that of another, in order to provide the most rigorous analysis of alternative development options and their related "go/no go" decisions. In addition, it is submitted that sequences examined for the purpose of this hearing must be realistic, considering not only costs but other factors, including reliability and environmental impact. MIPUG concludes that the Board is now able to examine all relevant sequence options in order to assess the Ontario Hydro sale decision."

(MIPUG, Written Argument, page 6)

> "Rejection of new thermal facilities as a major supply development option has a profound effect on the assessment of options. Essentially, this underlines Hydro's conclusion that the next generation of major new energy resources should continue to be provided from the undeveloped northern Nelson River resources. This, in turn, leads directly to focusing upon Wuskwatim and Conawapa as the two most obvious contenders; furthermore, the primary question in assessing these two hydraulic options simply becomes the selection of which comes first, i.e., if both options are

> inevitably going to be developed, the various environmental, capital, transmission and other associated implications for each option must eventually be faced and cannot be avoided through selection of some external option."

(MIPUG, Pre-filed Testimony, page 19)

After several days of evidence presented at the public hearing, Board Counsel summarized its position on the examination of Manitoba Hydro's alternative scenarios that was subsequently adopted by the Board:

> "Given that we and the majority of the intervenors agreed that the diversity agreements are a good deal for Manitoba, and the fact that the diversity agreements will likely be approved by all parties, we did not examine sequences 3 to 5 since they do not appear to be likely scenarios.
>
> Sequence 3 is the Ontario Sale without the NSP/UPA diversity agreements; Sequence 4 is no Ontario Sale, no diversity and Conawapa built first; and Sequence 5 is no Ontario Sale, no diversity and Wuskwatim built first.
>
> Sequence 6 is the same scenario as the preferred scenario except that it excludes thermal life assurance. From our review of the submission and of the intervenors' pre-filed testimony, it appears there is a consensus as to the benefit offered by thermal life assurance. The only issue is whether thermal life extension should also be considered, and Manitoba Hydro has indicated flexibility in that area. Therefore, a scenario without thermal life assurance does not appear to be likely.
>
> Sequence 7 is the same scenario as the preferred option except that it excludes demand-side management. Manitoba Hydro has acknowledged, in its rebuttal evidence and in its testimony, that its target is what it considers to be achievable. All of the testimony to date comes to the conclusion that cost-effective DSM programs are beneficial. The only issue is really whether Manitoba Hydro's targets are aggressive enough, therefore, we did not examine sequence 7.
>
> In summary, the diversity agreements, thermal life assurance, and the DSM programs were considered primarily in the context of Sequence 1 and 2. It appears that Conawapa and Wuskwatim will have to be built eventually with or without the Ontario Sale. The key question, of course, is when. Our first and final objective will be to conclude whether the Ontario Sale is a good deal for Manitoba."

(Transcript, Volume 5, pages 1135-1137)

Board Findings

The Board finds that of the scenarios advanced by Manitoba Hydro, only Scenario 1 (Manitoba Hydro's Preferred Development Plan) and Scenario 2 are realistic alternatives.

In agreeing with the conclusions of CAC/MSOS and CSC, the Board rejects Manitoba Hydro's Scenarios 3, 4, 5, 6 and 7 for the following reasons:

Scenarios 3, 4 and 5 all exclude the NSP/UPA diversity agreements. All of the intervenors and independent witnesses who expressed a view on the economic viability of the two diversity agreements recommended this component of Manitoba Hydro's development plans. The Board agrees with the intervenors' views that the diversity exchanges:

1) Offer flexibility in respect of generation planning and system operation.

2) Enable capital savings to be realized through deferment of future generation.

3) Provide reciprocal operating benefits.

4) Make good business sense and should be approved.

5) Are a likely component of a least cost program for satisfying the energy needs of Manitoba customers.

The diversity exchanges are further examined in the section entitled, "Diversity Exchange Agreements".

Scenario 6 excludes thermal life assurance. All of the intervenors who expressed a view on the feasibility of thermal life assurance agreed that keeping the thermal plants in good operating condition is a wise strategy. The Board concurs with the intervenors' views that thermal life assurance:

1) Provides Manitoba Hydro with an extra measure of flexibility from both a system planning and operating point of view.

2) Is likely to be even cheaper as a firming resource than construction of a new gas turbine due to the relatively limited capital costs to assure the life of existing thermal plants at Brandon and Selkirk and due to their use of relatively inexpensive coal instead of gas.

3) Will help to maintain an advantageous mix between thermal and hydraulic power in the Manitoba Hydro system.

4) Will keep open the option to life-extend thermal plants in the future.

The Board concludes that thermal life assurance is cost-effective and should proceed. However, it recommends that the environmental problems associated with fossil fuel thermal plants should be mitigated to the extent possible during Manitoba Hydro's upgrading of the plants.

Scenario 7 excludes demand-side management. Although some of the intervenors expressed concern that Manitoba Hydro's 100 MW DSM target was too conservative, all agreed that cost-effective DSM programs should be pursued by Manitoba Hydro. The Board concurs with this view.

As a result of eliminating Scenarios 3 to 7, the Board intends to focus on Conawapa and Wuskwatim as the two generation options and concurs with the view that the next generation of major new energy resources should continue to be provided from the undeveloped northern Nelson River resources.

The next section entitled, "Independent Witnesses' and Intervenors' Alternative Supply Scenarios", will also analyze the viability of alternative scenarios proposed by various intervenors. Most of these proposed alternatives are simply variations of Manitoba Hydro's Sequences 1 and 2.

The subsequent sections will analyze Manitoba Hydro's Preferred Development Plan, the Ontario Hydro sale contract, the economic evaluations of each of the proposed alternatives and the associated risks.

Independent Witnesses' and Intervenors' Alternative Supply Scenarios

Pursuant to 1(d)(iii) of Order in Council No. 177/90, the Board is directed to consider evidence that all reasonable alternative options have been considered and that the proposed capital projects have been selected on reasonable grounds, i.e., technical feasibility, cost efficiency, and reliability. In response to its mandate, the Board must regard the least cost plan as that which offers the least net cost among all those plans meeting reasonable standards of technical feasibility, efficiency, and reliability.

This section highlights alternative scenarios produced by the independent witnesses and intervenors. These alternative scenarios, produced as they were by the independent witness and intervenors with limited time and resources, did not display the same degree of development and analysis as did Manitoba Hydro's alternatives. Each of these alternative scenarios, however, offer variations on Manitoba Hydro's preferred and alternate scenarios and identify areas of contention and concern. The views of the independent witnesses and intervenors are discussed below along with Manitoba Hydro's response.

GWC

GWC proposed that a scenario having a capital cost lower than Scenario 2 - No Ontario Sale could be developed if northern hydro-electric generation were deferred to the maximum extent (page 22 of his pre-filed testimony). In his "Minimum Capital Cost Sequence", greater use would be made of base load combustion turbines and coal-fired plants; diversity exchanges and utility purchases would be maximized; and no additional export contracts would be executed.

GWC's basic premise was to utilize smaller, less capital-intensive plant to defer the larger hydro-electric developments. Although GWC could not estimate the net capital costs of this scenario, he did note that such a scenario would involve higher operating costs due to the greater reliance on thermal generation.

On page 22 of its Rebuttal Evidence, Manitoba Hydro noted that studies performed by Manitoba Hydro have concluded that new coal plants and simple cycle combustion turbines are not economic contenders for the next generation plant in scenarios 1 and 2; either Conawapa or Wuskwatim are less costly. The studies also indicated that coal plants and combustion turbines may be economic as subsequent plant additions later in the sequence but do not result in large sequence cost savings.

Manitoba Hydro confirmed these findings by calculating the sequence costs for GWC's proposed "Minimum Capital Cost Sequence". The findings showed that inclusion of the combustion turbines and coal plants would not result in sequence cost savings although the capital costs would be lower (see Appendix IX for Manitoba Hydro's calculations).

After having reviewed Manitoba Hydro's Rebuttal Evidence regarding his proposed scenario, GWC made the following comments at the public hearing:

> "The point of all of this was not necessarily to show that combustion turbines were a better alternative than the development of hydraulic plant on the northern rivers, but rather to satisfy myself that some other form of generation had been considered and that the process of taking a given number of plants, however many there are, six or so, and simply re-ordering them to generate seven different sequences was not a fallacy, that there was not something being overlooked in the process."

(Transcript, Volume 13, pages 3090-3091)

WRA

Although WRA did not develop any alternative scenarios, the recommendation was made that "Manitoba Hydro should examine customer self-generation and non-utility generation in order to obtain lower costs, to obtain energy supplies from diverse sources, and to create opportunity for industrial load management and useful coordination with non-utility generation" (page 72-73 of WRA's pre-filed testimony).

In response to WRA's testimony, Manitoba Hydro stated that it has a corporate policy of purchasing power from Non-Utility Generators (NUGs) at a price up to the avoided cost (pages 29-30 of its Rebuttal Evidence). The Corporation has discussed proposals with Trans-Canada Pipelines, Amy Street Steam Plant (headed by Winnipeg Hydro), REPAP Pulp and Paper Mill and the City of Brandon. As well, a proposal for converting a thermal unit at Brandon or Selkirk to burn used tires was considered. To date, none has appeared economic.

CAC/MSOS

CAC/MSOS developed numerous scenarios based on Manitoba Hydro's 1990 base load forecast, low load forecast and high load forecasts. In addition, CAC/MSOS developed scenarios based on their modified version of Manitoba Hydro's base forecast. Given that the Public Utilities Board accepts Manitoba Hydro's load forecast, only those scenarios using the base load forecast will be reviewed as possible alternatives. The following scenarios are contained in Appendix X and are summarized below.

Variations of Manitoba Hydro's Scenario 2

1) Manitoba Hydro's Scenario 2 with Thermal Life Assurance LA-2 (Table B-7 of pre-filed testimony)

   Under this scenario, thermal life assurance LA-2 would be substituted for Manitoba Hydro's LA-1 program, thereby deferring the retirement date of Brandon Units 1-4 until 2005. Therefore, Wuskwatim would not have to be built until 2006.

2) Manitoba Hydro's Scenario 2 with Thermal Life Extension LE-2 (Table B-9 of pre-filed testimony)

   This alternative scenario substitutes Manitoba Hydro's life assurance program with life extension program LE-2. LE-2 would life extend Brandon Units 1-4 to 2005, Brandon Unit 5 to 2014, and Selkirk Units 1-2 to 2011. Consequently, Wuskwatim would not be needed until 2010.

3) Manitoba Hydro's Scenario 2 with Extended Diversity and Thermal Life Extension LE-2 (Table B-11 of pre-filed testimony)

   In this alternative, existing and planned diversity exchanges are assumed to be renewed in order that diversity is not reduced within the planning period. Extended diversity, plus the impact of LE-2, would reduce the number of additional hydro plants required so that Manasan and First Rapids would not be required in the current planning period (to 2028). Wuskwatim would still be required in 2010.

4) Manitoba Hydro's Scenario 2 with 500 MW DSM by 2001, Extended Diversity and Thermal Life Extension LE-2 (Table B-13 of pre-filed testimony)

   This alternative is the same as the previous one except that DSM is increased from 100 MW to 500 MW. This proposal would reduce the number of additional hydro plants required and defer Wuskwatim to 2015.

5) Manitoba Hydro's Scenario 2 with Thermal Replacement, 500 MW DSM, Extended Diversity and Thermal Life Extension LE-2 (Table B-15 of pre-filed testimony)

   In this scenario, thermal replacement refers to replacing existing thermal plants when additional resources are needed. Replacing existing thermal capacity, in addition to increased DSM, extended diversity and LE-2), would defer the remaining required plants. Wuskwatim would not be required until 2021.

Variations of Manitoba Hydro's Scenario 1

6) Manitoba Hydro's Scenario 1 with 500 MW DSM, Extended Diversity and Thermal Life Extension LE-2 (response to CAC/MSOS undertaking filed as Manitoba Hydro Exhibit #MH-23)

   In this proposed alternative, CAC/MSOS changed the underlying assumptions of Manitoba Hydro's Preferred Development Plan. By assuming that DSM would increase by five times, that diversity exchanges would be renewed, and that the life of existing thermal plants would be extended, Conawapa would be deferred to 2002. Exhibit #MH-23 is contained in Appendix XI.

7) Manitoba Hydro's Scenario 1 with Ontario Sale Deferred for 10 Years, 300 MW DSM, Extended Diversity and Thermal Life Extension LE-2

   CAC/MSOS proposed a scenario with the Ontario Sale deferred for 10 years as a viable alternative to Manitoba Hydro's Preferred Development Plan. It was assumed that DSM would increase to at least three times the current target of 100 MW, that the diversity exchanges would be renewed and that life extension would prove feasible. Under these assumptions, Conawapa would be deferred until 2010.

With regard to the CAC/MSOS Scenarios 1, 2 and 3, the Board notes that these scenarios all rely on increased supply through renewal of diversity agreements, extended thermal life assurance or life extension of thermal plants in order to permit the deferral of major new generation stations.

The Board also notes Manitoba Hydro's comments regarding the timing of the next generation plant were as follows:

> "Manitoba Hydro's submission . . . is that without the sale, the next plant likely would be needed in 2002. There is a possibility it could be deferred to 2006 and it is also possible but highly unlikely that it could be deferred to 2010 or later."

(Transcript, Volume 22, page 5113)

Manitoba Hydro responded to CAC/MSOS' assumptions regarding life extension as follows:

> "Manitoba Hydro argues that thermal life extension is reasonable to consider as a possibility, but considers that it should not be counted upon at this time as a central assumption because of the inherent uncertainties in the cost of maintaining the units, in the reliability of the units and because of the risk that life extension would result in more stringent environmental measures than those assumed being required.
>
> Furthermore, deferring plants by extending thermal life would result in a lower overall system reliability even if the reliability of the thermal units themselves does not deteriorate.
>
> Finally, Manitoba Hydro has shown that the assumption of life extension as opposed to life assurance does not significantly affect the benefits of the Ontario Sale."

(Manitoba Hydro, Written Argument, pages 65-66)

CAC/MSOS' assumption that the diversity agreements would be renewed for the planning period 1990-2028 was also disputed by Manitoba Hydro. Manitoba Hydro's evaluations assumed that the diversity exchanges would terminate at the conclusion of their contracts in 2015 and 2016. Manitoba Hydro has testified that it would not be appropriate to assume that the diversity agreements could be extended at this time, although both parties would continue them in the future if mutually beneficial.

According to Manitoba Hydro, there is a possibility that the diversity in each party's system would not continue to exist to the same extent as at present for the following reason:

> "DSM programs are tending to reduce the availability of diversity both in Manitoba and in the neighbouring systems. With the currently committed diversity, there is little additional diversity available, and any reduction will

> influence the attractiveness of future exchanges. The MAPP pool members have expressed some concern that the diversity in the pool is reducing, with continuing reduction expected in the future . . ."
>
> (Manitoba Hydro, Written Argument, page 38)

Manitoba Hydro also notes that an assumption to extend the diversity exchanges would have the impact of raising the Ontario Sale benefits.

With regard to the CAC/MSOS Scenarios 4,5 and 6, the Board notes that each requires Manitoba Hydro to achieve a 500 MW DSM target by 2001. In the previous section entitled, "Meeting the Load Forecast", the Board concluded that, for the purpose of generation planning, Manitoba Hydro's 100 MW DSM target is the one that that should be used for system reliability purposes. Therefore, these three scenarios are rejected.

With regard to CAC/MSOS Scenario 7, also referred to as CAC/MSOS' 2010 Scenario, the Board notes the comments made by MIPUG during the public hearing:

> "Mr. Roman gives you some new evidence, which remains totally untested, that the sale as presently proposed yields lower cost per customer than a ten-year delay. At the end of this section, however, CAC/MSOS suggests that you should ignore this least-cost approach and gamble; that we can do better through delay and renegotiation. I protest there is no tested evidence in this material to justify the recommended gamble as being a least-cost approach for Manitoba customers."
>
> (Transcript, Volume 22, page 4998)

CAC/MSOS' suggestion that the Ontario Sale should be turned down on the basis that a better deal could be negotiated in the future was also responded to by Manitoba Hydro:

> "As explained by Mr. Brennan, by 1989, Manitoba Hydro had reached a point in time where construction to meet its own load was imminent and the sale of electricity to Ontario represented an opportunity to lower the cost of electricity in Manitoba (Transcript, Volume 1, page 89).
>
> Ontario Hydro was similarly, and coincidentally, at a point in time where its plans for meeting future loads were under review. In addition, pressures to meet higher than expected load growth and emission restrictions make purchases from Manitoba attractive."
>
> Manitoba Hydro testified that:
>
>> "If we were to go to Ontario Hydro at this point in time and tell them I am sorry, the deal is off, I don't hold out a great hope for doing business with them 10 years down the road."
>
> (Transcript, Volume 5, page 1170)

CSC

CSC did not initially generate any of its own alternative development scenarios; however, CSC suggested alternative supply-side resources which were previously discussed under the section entitled, "Meeting the Load Forecast" and which are listed below along with Manitoba Hydro's response:

1) Rerunnering of existing hydro facilities.

   In regards to rerunnering of units, Manitoba Hydro stated on page 29 of its Rebuttal Evidence that studies are underway at Kettle and have been initiated at Kelsey. However, rerunnering of units would result in peak capacity improvements as opposed to dependable energy improvements; therefore, future plants could not be deferred using this supply-side resource.

2) Firming up existing supply with low capital cost thermal units.

   In regards to firming strategies, Manitoba Hydro notes on pages 18-21 of its Rebuttal Evidence that the Preferred Development Plan includes a number of firming strategies in the form of existing non-hydraulic sources. A main non-hydraulic firming strategy is the use of the existing coal-burning thermal stations which are mainly operated in drought years. The Preferred Development Plan includes life assurance of the Brandon and Selkirk plants with protection of the option to extend their life at a later date.

   Each life extension decision will depend on the age of the plants and their reliability, in addition to economic considerations. Decisions required at this time on other aspects of the Preferred Development Plan are not altered by the assumption in regards to life extension. In Appendix X, Section B2 of its Submission, Manitoba Hydro prepared an economic analysis which indicates that, under Scenario 2, life extension may allow Wuskwatim to be deferred to 2009. However, the resulting cost saving of $30 million does not significantly alter the relative economics of the Ontario Sale.

3) Development of alternative resources such as small hydro, biomass and cogeneration.

   The probability of the economical development of small hydro in Manitoba is minimal due to the remoteness of the sources, then small capacity, and costs. Cogeneration is considered by Manitoba Hydro and is discussed in the section entitled, "Meeting the Load Forecast". Manitoba Hydro has been involved with investigations utilizing wind and determined this source to be unreliable and expensive. Solar generation is deemed by Manitoba Hydro to be an inappropriate source due to the low capacities available, the present state of development, and cost.

4) Inclusion of the Kelsey extension and Notigi generation projects in Manitoba Hydro's scenarios.

In response to CSC's recommendation to include the Kelsey extension project in its scenarios, Manitoba Hydro noted on page 27 of its Rebuttal Evidence that the Kelsey extension cost (even without the associated transmission) is 43% higher than that of Conawapa and Bipole III and higher than every other option identified on the Nelson and Burntwood Rivers. CSC subsequently acknowledged that they made an error with regard to Kelsey costs.

With regard to Notigi, Manitoba Hydro stated on page 28 of its Rebuttal Evidence that the per unit cost of Notigi, including required transmission, is $101/MW.h, which is higher than that of Conawapa ($89/MW.h) and Wuskwatim ($66/MW.h). The Corporation noted that Notigi was not included in its scenario evaluations because Wuskwatim was significantly less costly and because of Notigi's small size (110 MW) which would necessitate another new plant being built one or two years later. Manitoba Hydro concluded that the inclusion of Notigi in the generation expansion analysis would not have altered the relative scenario economics.

MIPUG

During the public hearing, MIPUG conducted a cross-examination of the Manitoba Hydro panel in which it investigated the requirement for additional generation (Transcript, Volume 14, pages 3222-3348). MIPUG stated that: "We've provided Manitoba Hydro with a graphic view of various supply and demand balances for power that have emerged from the evidence to date, particularly from Mr. Todd's evidence. We found it useful to simplify the analysis with graphs focusing on when shortfalls first occur under various assumptions." (Transcript, Volume 14, pages 3247-3248). MIPUG's analysis was filed as Exhibit #MIPUG-9 which is summarized below and which is included as Appendix XII.

In Exhibit #MIPUG-9, MIPUG analyzed capacity and energy shortfalls using the 1990 Load Forecast under various scenario to determine when the next generating station would be needed. Existing plant and export levels were reviewed in the context of the present DSM targets.

Although MIPUG's analysis did not recommend any one scenario, it indicates that additional supply and/or reduced loads may be required prior to such "shortfall dates" in order to ensure adequate system reliability. Commitments regarding new capital development programs would normally be required many years prior to the shortfall dates indicated above if supply shortfalls are to be avoided.

MIPUG's projected MW and GW.h shortfall periods for the period 1990 to 2028 are summarized on the following page.

Projected Capacity Shortfalls Under Varying Assumptions

Scenario	First Year of Capacity Shortfall
Existing Plant with LA-1	1999
Conawapa/Ont. Sale with LA-1	1999
Existing Plant with LA-1 and Diversity	2002
Conawapa/Ont. Sale with LA-1 and Diversity	2011
Conawapa/Ont. Sale with LA-1, Diversity and 2x DSM	2012
Conawapa/Ont. Sale with LA-1, Diversity and 5x DSM	2015
Existing Plant with LA-1 and Diversity Extension	2009
Existing Plant with LE-2, and Diversity Extension	2011
Existing Plant with LE-2, Diversity Extension and 2x DSM	2012
Existing Plant with LE-2, Diversity Extension and 5x DSM	2017
Conawapa/Ont. Sale with LE-2 and Diversity Extension	2012
Conawapa/Ont. Sale with LE-2, Diversity Extension and 2x DSM	2014
Conawapa/Ont. Sale with LE-2, Diversity Extension and 5x DSM	No Shortfall*

* "No shortfall" indicates that, with this development scenario, no other generation will be needed to meet capacity demands in the future.

MIPUG's conclusion as to its analysis was provided in its final argument:

> "In summary, the evidence indicates that demand/supply balance impacts with respect to the Ontario Hydro sale have been examined under a wide variety of different potential planning assumptions. The analysis confirms the relevance of the Ontario Sale for providing facilities that are likely to be required by Manitoba domestic customers during the next two or three decades. The analysis also helps to explain why the Ontario Sale benefits are not significantly affected by sensitivity analysis pertaining to different thermal plant options, diversity agreement options, or DSM target options."
>
> (MIPUG, Written Argument, page 11)

MKO

MKO did not develop any alternatives to Manitoba Hydro's Preferred Development Plan. At present, it "does not support or oppose the development of the Conawapa hydro-electric station or the Bipole III transmission project" (page 10 of its closing argument).

NFC

Although NFC did not generate any alternative scenarios, it had the following comments regarding Manitoba Hydro's Preferred Development Plan (page 11-12 of its closing argument):

"The NFC opposes in principle the construction of any dams on the Nelson River other than Conawapa, and any dams on the Burntwood River, including specifically Wuskwatim, until broad study is completed on the impact of hydro-electric development on northern ecosystems and aboriginal communities and until and unless there can be general agreement among all parties, including the five Bands of the NFC, concerning the acceptability of Wuskwatim or other like works.

Manitoba Hydro's Sensitivity Analyses of Other Proposed Alternatives

In addition to the alternatives proposed and discussed above, Manitoba Hydro performed additional sensitivity analysis for variations of scenarios 1 and 2 proposed by the intervenors. This additional analysis was filed by Manitoba Hydro in Exhibit #MH-40 and briefly summarized as follows (note that the net cost difference between each variation of scenarios 1 and 2 is presented in 1989 present value dollars and was calculated using a 5.25% real discount rate):

1) Sensitivity 0 - Base case assumptions with thermal life assurance LA-1 for both Scenarios 1 and 2 (Scenario 1 - Conawapa required in 2000 and Scenario 2 - Wuskwatim required in 2002). The net benefit of Scenario 1 is $711 million.

2) Sensitivity 1 - Base case assumptions with thermal life assurance LA-1 for Scenario 1 and LA-2 for Scenario 2 (Scenario 1 - Conawapa required in 2000 and Scenario 2 - Wuskwatim required in 2006). The net benefit of Scenario 1 versus Scenario 2 is $697 million.

3) Sensitivity 2 - Base case assumptions with thermal life assurance LA-1 for Scenario 1 and thermal life extension LE-2 for Scenario 2 (Scenario 1 - Conawapa required in 2000 and Scenario 2 - Wuskwatim required in 2010). The net benefit of Scenario 1 versus Scenario 2 is $641 million.

4) Sensitivity 3 - All diversity exchanges were assumed to be extended to the end of the study and thermal life extension LE-2 was assumed for both Scenarios 1 and 2 (Scenario 1 - Conawapa required in 2000 and Scenario 2 - Wuskwatim required in 2010). The net benefit of Scenario 1 versus Scenario 2 is $665 million.

5) Sensitivity 3A - All diversity exchanges were assumed to be extended to the end of the study and thermal life assurance LA-1 was assumed for both Scenarios 1 and 2 (Scenario 1 - Conawapa required in 2000 and Scenario 2 - Wuskwatim required in 2002). The net benefit of Scenario 1 versus Scenario 2 is $744 million.

6) Sensitivity 4 - All diversity exchanges were assumed to be extended to the end of the study, demand-side management was targeted at 500 MW and thermal life assurance LA-1 was assumed for both Scenarios 1 and 2 (Scenario 1 - Conawapa required in 2001 and Scenario 2 - Wuskwatim required in 2015). The net benefit of Scenario 1 versus Scenario 2 is $561 million.

7) Sensitivity 5 - All diversity exchanges were assumed to be extended to the end of the study, rerunnering included, demand-side management was targeted at 500 MW up to 2000 and at 1,000 MW by 2020, and thermal life assurance

LA-2 was assumed for Scenario 1 and thermal life assurance LA-1 was assumed for Scenario 2 (Scenario 1 - Wuskwatim required in 2002 and Scenario 2 -no stations required before 2028). The net benefit of Scenario 1 versus Scenario 2 is $812 million.

8) Sensitivity 6 - Base case assumptions with interruptible export rates increased by 10% in the sale scenario and thermal life assurance LA-1 assumed for both Scenarios 1 and 2 (Scenario 1 - Conawapa required in 2000 and Scenario 2 - Wuskwatim required in 2002). The net benefit of Scenario 1 versus Scenario 2 is $816 million.

Although these sensitivities are based on the 1990 Base Load Forecast and therefore are not directly comparable to the $696 million net benefit of Manitoba Hydro's Scenario 1 versus Scenario 2 (which uses the 1989 Base Load Forecast), these results do indicate that the Preferred Development Plan is profitable under a wide range of scenarios and sensitivities.

This may lead to the conclusion that any one of these variations of Manitoba Hydro's Preferred Development Plan is acceptable and that perhaps one of these is an optimal alternative. However, Manitoba Hydro had serious reservations about the feasibility, costs, risks, and likelihood of a number of these scenarios, particularly the ones which involved high amounts of demand-side management (i.e., 5x to 10x Manitoba Hydro's 100 MW target). Manitoba Hydro cautioned that it had not had the opportunity to perform analyses of the range of critical factors such as reliability, energy security, risks, detailed economics, financial effects, and environmental impacts for these scenarios.

Board Findings

With regard to CAC/MSOS' 2010 Scenario, the Board makes the following observations:

1) This scenario was developed during the public hearing. As a result, Manitoba Hydro was unable to respond to CAC/MSOS' request to perform a detailed analysis on this alternative within the time frame of the public hearing, partly because of its complexity and partly because it had undertaken (and eventually completed) a great many more similar requests from other intervenors, including six others from CAC/MSOS. In consequence, the Board agrees with MIPUG that this proposition remains insufficiently tested.

2) This scenario incorporates a 300 MW DSM target which is a figure in excess of Manitoba Hydro's 100 MW target by 2001, which the Board accepts. Although the Board also recommended that Manitoba Hydro's DSM target be accelerated if possible which may result in the 300 MW target being exceeded, prudence requires that Manitoba Hydro, at its present stage of DSM development, rely on its 100 MW target for generation planning purposes.

3) The Board's most significant objection to CAC/MSOS' 2010 Scenario is that despite CAC/MSOS' assertion that Manitoba Hydro's low generation costs will make it possible to negotiate a new contract with Ontario Hydro in the future, that conclusion is countered by the following arguments:

i) In the next 10 to 20 years, Ontario Hydro may find another supplier or may have unprecedented success with its DSM programs. Ontario's load requirement may also decrease in the future due to a structural reduction in its present dominant position in Canadian manufacturing.

ii) Furthermore, if Ontario continues to prosper towards the end of the century and does not find another low cost supplier, the prospects of another firm sale at enhanced prices in addition to the present sale is a real possibility.

iii) Although a least cost scenario is required to evaluate the benefits of the Ontario Sale and to ensure that those benefits are neither overstated or understated, the scenario must also be realistic considering not only cost but also factors such as system reliability and environmental impacts.

iv) Deferral of the Ontario Sale at this time would result in the deferral of benefits to Manitoba Hydro which would result in higher consumer rates.

With regard to the other scenarios proposed by the independent witnesses and intervenors, the Board notes that many of these scenarios generally rely on increased load reductions through demand-side management and/or on increased supply through renewal of diversity agreements and life extension of thermal plants in order to permit the deferral the major new generating stations.

As the Board previously concluded in the section entitled, "Meeting the Load Forecast", setting a high DSM target for generation planning would serve no useful purpose since using an unrealistic figure for planning purposes creates risk in terms of system reliability. The level of the DSM target assumed for planning purposes today will not significantly affect the conclusions concerning the profitability of the Ontario Sale nor will it affect any current decisions regarding the construction of facilities. However, the effectiveness of Manitoba Hydro's current and future DSM programs will be monitored at future rate hearings.

With regards to the renewal of diversity agreements, the Board concurs with Manitoba Hydro's position that an assumption of extended diversity exchanges could not be made for generation planning purposes. Because such a supply-side assumption may not be realizable in the future, making this assumption would increase system reliability risk.

The same considerations apply to thermal life extension which may or may not be capable of realization in the future. It may be possible in a technical sense to extend the life of Manitoba Hydro's thermal plants. Whether it will be economic to do so is less certain, and whether it will be environmentally permissible to do so will depend on the degree to which society may be willing to tolerate avoidable atmospheric pollution in future years.

Manitoba Hydro has also performed extensive sensitivity analyses for variations of Scenarios 1 and 2 proposed by the intervenors. The results of the sensitivity analyses indicate that Manitoba Hydro's Preferred Development Plan is profitable under an extremely broad range of possible futures. In all cases, the modified Scenario 1 was a lower cost alternative than the modified Scenario 2.

In summary, with regard to the intervenors' proposed alternatives, the Board concludes that any development plan which depends heavily on large DSM savings and on supply-side resources which Manitoba Hydro may or may not be able to realize carries unquantifiable but nevertheless, real risks in terms of system reliability. In addition, because many of these alternatives have only been analyzed from a revenue perspective, there is not enough evidence to support any of these alternatives as being an optimal generation expansion plan.

The Board also concludes from the above analyses that the benefits and risks of the Ontario Sale are the determining factor in deciding between Manitoba Hydro's Scenarios 1 and 2. The Ontario Sale will be reviewed in the following sections which discuss the components of the Preferred Development Plan, the terms of the Ontario Sale contract, the economic evaluation of Scenarios 1 and 2, and the risks associated with the Ontario Sale.

Manitoba Hydro's Preferred Development Plan

Order in Council No. 177/90 assigns this Board the duty of reviewing Manitoba Hydro's proposals in respect of major capital projects required for generation and transmission during the period 1990 to 2009.

As indicated in a previous section entitled, "Manitoba Hydro's Alternative Supply Scenarios", Manitoba Hydro has developed a Preferred Development Plan to meet the expected future needs.

The Manitoba Hydro Preferred Development Plan was also referred to at the hearing as Manitoba Hydro's preferred scenario or Manitoba Hydro's Scenario 1.

The Preferred Development Plan is based on the following initiatives undertaken by Manitoba Hydro:

1) The 1,000 MW Ontario Hydro sale, (discussed further in the upcoming section entitled, "Contracts with Ontario Hydro").

2) A 150 MW seasonal diversity exchange with Northern States Power (NSP), and a 150 MW seasonal diversity exchange with United Power Association (UPA) (discussed further in the upcoming section entitled, "Diversity Exchange Agreements").

3) The thermal plant life assurance program, (previously discussed in the section entitled, "Meeting The Load Forecast").

4) The 100 MW demand-side management target (previously discussed in the section entitled, "Meeting The Load Forecast").

To implement the initiatives of its Preferred Development Plan, Manitoba Hydro proposes to construct various facilities. The following sections from Manitoba Hydro's evidence describe and explain the new facilities contemplated.

Facilities in the Preferred Scenario

As a consequence of the 1000 MW Ontario Hydro sale, Manitoba Hydro proposes to construct:

1) The Conawapa Generating Station on the Nelson River

   The Conawapa site is located 27 kilometers (17 miles) downstream from the Limestone Generating Station. The plant would have 10 generating units with a total capacity of 1,390 MW and would be similar in general arrangement and size to Limestone. Conawapa and Bipole III transmission facilities would provide approximately 11,000 person-years of employment during construction.

As at Limestone, Conawapa's forebay would be contained within the natural river banks and, hence, there would be minimal flooding of the adjacent areas. The station would be operated in concert with the upstream stations as a run-of-the-river plant with minimal forebay fluctuations, but with variable discharges. For a 2000 in-service date, the commitment dates for the various front-end activities are as follows:

a) Winter 1990/91 - Sundance to Conawapa all-weather access road and construction power transmission for an in-service date of the spring of 1992.

b) Spring 1991 - Camp site preparation and associated infrastructure construction (sewer and water, etc.) to accommodate 500 people by the spring of 1992.

c) Summer 1992 - Construction of Stage I cofferdam for completion by the winter of 1994.

d) Fall 1994 - General Civil Contract with first concrete placement by late summer of 1995.

The estimated in-service costs of the Conawapa generating station consist of $3,781 million for the generating station and $130 million for the transmission line from Henday to Riel for a total of $3,911 million.

2) A New Transmission Facility From The Nelson River To Southern Manitoba (Bipole III)

A new transmission line would be required in 2000 when Conawapa Generating Station is added to the system. To transmit Conawapa power to Southern Manitoba, Bipole III is planned as the third high-voltage direct current (HVDC) transmission line from Henday Station at the Nelson River to Riel Station near Winnipeg. The project is described in the following sections and shown on the diagram in Appendix XIII.

Subject to environmental assessment and regulatory approval, Manitoba Hydro would design and construct a +/- 500kV DC transmission line from Henday to Riel. The transmission line length is approximately 820 km for a line route on the east side of Lake Winnipeg.

A 500kV AC transmission line, 48 km long, between Dorsey and Riel stations would be required for reliability reasons. It would provide a connection between the two HVDC converter stations during certain emergencies.

The existing station at Henday would be expanded to connect Bipole III transmission facilities to the Nelson River generating stations. Associated terminal facilities would include HVDC rectifier equipment, ground electrode, and AC switching equipment.

A new HVDC converter station would be built at Riel south-east of Winnipeg, complete with ground electrode, and DC and AC switchyards to terminate Bipole III transmission in southern Manitoba. Synchronous condensers would be added, as well as equipment to control power flows, stabilize voltages, and provide reactive power compensation necessitated by the addition of Bipole III to the system.

A Telecontrol system between Bipole III terminal stations at Henday and Riel would be required to provide required communication for operation and control.

At Dorsey Station, high speed switches would be installed to facilitate connection of Bipole III to one of the other two bipoles to maintain system reliability in case of emergency.

During the public hearing, Mr. Lambert discussed the increased north-south reliability provided by the construction of Bipole III:

". . . the majority of the energy for the Manitoba system is generated in the north, and it is used to serve the loads in the south, and the integrity of the north-south transmission is very crucial to the operation of Manitoba Hydro, and that is why the location of Bipole III on the east side of Lake Winnipeg will provide separation of Bipole III from the existing lines and reduce the possibility of a single event forcing all lines out of service at the same time.

With the completion of Limestone, spare transmission capability from the north will no longer be available. Manitoba Hydro, with the addition of Limestone, will not enjoy the benefits of having had (sic) spare transmission capability on the system. Spare capability to cover periods of forced outage will not generally exist, and the addition of Bipole III will enhance the reliability of the system in that respect."

(Transcript, Volume 2, pages 237-238)

The estimated in-service costs of Bipole III (in-service date is 2000) are listed below.

Bipole III Costs

	$Million's
Henday-Riel 500kV HVDC transmission line	471
Henday Station, HVDC line termination and rectifier	485
Riel Station, HVDC line termination, converter, synchronous condensers, ground electrode, DC paralleling switching	702
Miscellaneous: Dorsey Station modifications, telecontrol	37
TOTAL	1,695

3) A New Transmission Facility To Ontario

The Manitoba-Ontario Facilities Agreement for the 1,000 MW firm sale specifies a total design transfer limit of 1,500 MW to Ontario Hydro by the year 2000. A new transmission line would be required to achieve, together with the existing two 230kV tie lines from Whiteshell to Kenora, the required transfer capability. System studies to optimize the conceptual design of the new facilities are ongoing and will not be finalized before the end of 1990. The following project description is a provisional scheme on which negotiations for the sale were based.

The new interconnection would be a 500kV AC transmission line between Riel Station near Winnipeg to Dryden, Ontario. The portion of the line in Manitoba to the Ontario border would be approximately 135 km long.

At Riel, facilities would be required to step up the voltage received from Bipole III inverter transformers from 230kV to 500kV for transmission to Ontario. Line reactors, phase angle regulators, shunt capacitors, 230kV and 500kV circuit breakers, and associated switchgear and accessories would be installed to accommodate the termination of the new transmission line.

A telecontrol system to Ontario would be installed for communication, protection, and control.

The estimated in-service costs of the Ontario transmission line consist of $95 million for the 500kV transmission line from Riel to the Ontario border and $122 million for the Riel Station and Ontario Hydro interconnection facilities, together totalling $217 million.

As a consequence of the diversity exchange initiatives with NSP and UPA, Manitoba Hydro proposes to:

4) Make interconnection improvement with Minnesota, which may include the construction of a new transmission line.

According to the Diversity Exchange Agreements with NSP and UPA, the transmission transfer capacity between Manitoba and the U.S. is to be increased by at least 300 MW in 1995. The negotiations for the diversity agreements were based on the upgrading of the existing 230kV and 500kV transmission lines between Manitoba and the U.S., and the addition of a new 230kV line from the Winnipeg area to Winger station in Minnesota.

Alternatives are being investigated by Manitoba Hydro and the U.S. utilities to economically achieve the required transfer capability by a greater degree of upgrading of existing tie lines, without building the new transmission circuit.

Approximately 150 km of 230kV transmission line would be constructed from the vicinity of the future Riel station, via Richer, to the Manitoba-Minnesota border. Manitoba Hydro also plans to pre-build 48 km of 500kV transmission required for the future interconnection of the Bipole III transmission. The line would temporarily operate at 230kV as an extension of the new Minnesota tie line to Dorsey.

A 230kV circuit breaker and associated equipment at Dorsey to terminate the new 230kV tie line to Minnesota would be required. After Bipole III comes into service in 2000, the Minnesota line would be re-terminated at Riel and the Dorsey-Riel portion would be operated at its 500kV design voltage.

A telecontrol system to Minnesota would be installed for communication, protection, and control.

The estimated in-service costs of the additional 300 MW capacity in the Manitoba-Minnesota Transmission is $29 million. The Dorsey-Riel transmission line section would cost $25 million for a total of $54 million.

In summary, Manitoba Hydro's Preferred Development Plan will be further examined in the following sections which will review the terms of the Ontario Sale, the economics of the preferred scenario versus Scenario 2 and the related risks.

Contracts with Ontario Hydro

Pursuant to paragraph 1(a) of Order in Council No. 177/90 the Board has reviewed the recent agreements signed between Manitoba Hydro and Ontario Hydro to supply Ontario Hydro with a firm supply of power starting in the year 2000.

The proposed 1000 MW sale to Ontario Hydro is one of the four initiatives included in Manitoba Hydro's Preferred Development Plan, and is clearly the most important, and as the hearing record indicates, the most controversial.

At the centre of the controversy was the issue of whether the benefits sufficiently offset the risks of the proposed sale.

In this section of the report the Board examines the terms and conditions of the actual sale agreement between Manitoba Hydro and Ontario Hydro. The Board will determine whether the words in (or omitted from) the agreement are of such concern as to dictate that approval of the Ontario Hydro Sale Agreement be denied.

The conceptual question of whether Manitoba Hydro should be entering into an export sale agreement at this or any other time, with Ontario Hydro is an issue that is addressed in subsequent sections of this report.

The Agreements which give effect to the proposed sale to Ontario Hydro were signed by officials of Ontario Hydro and Manitoba Hydro on December 7, 1989. These agreements are the:

1) System Participation Agreement, Manitoba - Ontario Interconnection between the Manitoba Hydro Electric Board and Ontario Hydro dated December 7, 1989 (System Participation Agreement).

2) Facilities Agreement, Manitoba - Ontario Interconnection between the Manitoba Hydro Electric Board and Ontario Hydro dated December 7, 1989 (Facilities Agreement).

Manitoba Hydro's Justification

According to Manitoba Hydro, when an agreement to sell power to Ontario Hydro, from 1998 to 2003, was entered into in August, 1987, one of the conditions of that Agreement was the continuation of negotiations for possible larger transactions. Until August, 1988, Manitoba Hydro and Ontario Hydro were negotiating and attempting to maximize the transactions between them on existing transmission facilities. At that time Ontario Hydro expressed an interest in larger transactions of up to the total output of Conawapa.

(Manitoba Hydro, Submission, Appendix VII)

> "At this point Thermal Life Assurance was not a certainty and the Hydro Board was acutely aware that Hydro would, in all probability, have to build either

> Conawapa or Wuskwatim by 1999, with all the costs and risks to be borne by Manitoba consumers unless export sales could be negotiated.
>
> A decision was made to vigorously pursue the Ontario sale with one overriding constraint; Manitoba consumers had to be better off in every year of the sale than would otherwise be the case..."
>
> (Transcript, Volume 1, page 75)

In his opening remarks, the President and Chief Executive Officer of Manitoba Hydro emphasized some of the major benefits that Manitoba Hydro believes will be realized with the Ontario sale:

> "A) Lower electricity rates - the fundamental characteristic of the Ontario Hydro sale is that electricity rates to Manitoba consumers will be lower in each and every year of the sale than they would be without the sale.
>
> B) Higher reliability - interconnections with neighbouring utilities play a very important role in providing system security to Manitoba. During periods of difficulty, Manitoba Hydro can draw on neighbouring utilities for support. The planned new transmission line to Ontario together with the construction of Conawapa and Bipole III will significantly improve Manitoba Hydro's system reliability.
>
> C) Lower risk - if Manitoba Hydro was building Conawapa solely for our own requirements, all risk would be ours. Instead, Manitoba Hydro is negotiating an agreement which sells a portion of that power to Ontario retaining a smaller but important portion for our own use and essentially sharing the risk with Ontario Hydro.
>
> It should be noted that the contracts entered into contain clauses which protect against the risk of inflation because actual inflation rates are used. In addition, the annual capacity charge will utilize Manitoba Hydro's actual cost of borrowing during the period of construction of Conawapa. With the terms and conditions negotiated, a number of possible futures were modelled and the transaction provides positive benefits under a wide range of assumptions.
>
> One final point regarding the sale is that as we all know Manitoba Hydro is in the business of providing electricity over the long haul; that is, when we build a hydraulic generating station, it is going to be around for at least 100 years, so in that context, the sale to Ontario Hydro is for a relatively short duration in relation to the total life expectancy of the plant.

> This means that the electric power consumers of the year 2022 and beyond will continue to reap the tremendous benefits of having a generating station that was largely paid for out of the revenues of the Ontario Hydro sale."

(Transcript, Volume 1, Pages 89-91, Mr. Brennan).

The Board did not hear evidence from representatives of Ontario Hydro, but was advised that Ontario Hydro is currently experiencing a rapid growth in load and is looking for alternative supplies to complement its traditional power sources. Ontario Hydro's existing and approved demand-side management programs and generating plants are forecast to be sufficient in meeting the utility's needs until 1996 under the most likely load growth. By the year 2019 additional Ontario Hydro requirements are estimated to be 8000 MW under the most likely load growth and 22,000 MW under a forecast of high load growth.

The Board was further advised that Ontario Hydro had four options in meeting their future demands:

1) Demand options such as load shifting and efficiency improvements.

2) Small scale supply options including small hydraulic, co-generation, wind and solar.

3) Large scale supply options such as hydraulic, nuclear, coal, gas and oil.

4) Purchases from neighbouring utilities.

The potential contribution from demand options and smaller scale supply options was considered insufficient in meeting Ontario Hydro's long-term needs.

Of the large scale supply options, nuclear, coal, oil and gas are the only options with large resource availability.

(Manitoba Hydro, Submission, Appendix VII, Appendix B)

The Board was advised that importing hydro power from neighbouring provinces is foremost among the options that Ontario Hydro is considering at this time because a large import contract, commencing in the year 2000, would diversify Ontario Hydro's generation sources, improve system reliability due to added interconnection facilities, and widen the lead time for construction of new coal and/or nuclear plants.

In terms of a purchase from Manitoba Hydro, Ontario Hydro would also derive benefits from increased integration of their western system into the eastern Ontario system. In addition, coal and nuclear plants have been subjected to considerable regulatory and environmental concerns which have resulted in greater uncertainty pertaining to forecasted in-service dates for these types of generating plants.

Manitoba Hydro's Negotiating Considerations

The management of Manitoba Hydro was given a list of key considerations, that were developed on a policy basis, to work towards during their negotiations with Ontario Hydro.

These considerations are summarized as follows:

1) Provision of significant benefits to Manitoba Hydro to be measured by a projected revenue to cost ratio. A 2:1 ratio was the initial target.

2) Consumer rates in Manitoba were to be lower in every year of the sale than they otherwise would be without the sale.

3) A borrowing program which would not be expected to strain the borrowing capacity of the Province of Manitoba.

4) An obligation for Ontario Hydro to "take or pay" for the amount of power they are committed to take each year under the contract.

5) A construction schedule acceptable to Manitoba Hydro.

6) A sale sequence that would not lead to the advancement of a coal-fired plant in Manitoba.

7) Sale arrangements which would give a priority to firm Manitoba load in the event of outages and which would be consistent with pre-existing export commitments.

8) Sale arrangements which would provide some flexibility in the delivering of energy in periods of low water conditions in Manitoba.

9) Provision of transmission capacity for increased interruptible energy sales and/or access to new markets on transmission facilities associated with the sale.

10) Enhanced security for the Manitoba system in addition to the increased system security provided by the presence of Bipole III.

(Exhibit #MH-14)

Manitoba Hydro's final assessment of the sale to Ontario Hydro was to include consideration of how closely all of the considerations were met as well as any compromises that arose during negotiations.

Since the establishment of those negotiating considerations, certain other initiatives (i.e., DSM, diversity exchanges) have been undertaken by Manitoba Hydro. The net result, according to Manitoba Hydro, is that, "we still believe that the target at the time was satisfactory, and that the revenues are sufficiently in excess of the costs to more than offset the risks involved, and that the impact will be beneficial on consumers".

(Transcript, Volume 18, page 4067)

Manitoba Hydro claims that the Ontario Hydro sale is further justified because:

1) The construction of Conawapa is the most economic option considering the current Manitoba Load forecast.

2) The construction of Conawapa will provide enough capacity to serve Manitoba load until 2007 as well as provide for the sale to Ontario Hydro.

3) There are benefits of system reliability and of expansion into an alternate market for surplus energy sales.

System Participation Agreement

The System Participation Agreement is the primary of two "recent agreements" referred to in Order in Council No. 177/90 and reviewed by the Board.

The System Participation Agreement is the operative document that is to effect the firm sale of up to 1000 MW of electricity from Manitoba Hydro to Ontario Hydro.

The present installed capacity of the Manitoba Hydro system is just over 4000 MW; the completion of the Limestone Generating Station in 1992 will increase this to over 5200 MW and Conawapa will add another 1300 MW. The 1000 MW represents about twelve years' load growth in Manitoba. In contrast, the Ontario Hydro system is much larger than Manitoba Hydro's, with a present installed capacity of just over 30,000 MW. The 1000 MW purchase represents about two years' load growth for Ontario Hydro.

The System Participation Agreement was concurrently executed with the Facilities Agreement and is included as Appendix XVI to this report. The following is a brief summary of certain salient terms and conditions:

Section
No. Terms of Agreement

1.05 The Agreement with Ontario Hydro is to run from November 1, 2000 to October 31, 2022.

2.01 Capacity, Firm Energy and Surplus Energy to be Made Available by
10.0 Manitoba Hydro to and Ontario Hydro

During the term of the Agreement, the firm energy and capacity to be supplied to Ontario Hydro steps up in the years 2000 to 2003 to a maximum of 5698 GWh per year and 1000 MW and then steps down to zero in the years 2018 to 2021.

If Manitoba Hydro is not in a low flow condition, or will not be put in a low flow condition it shall make available, and Ontario Hydro may, at its option, purchase supplementary energy, in addition to firm energy, to the limit set out on the following page:

Capacity, Energy and Surplus

Contract Year	Capacity	Firm Energy	Annual Capacity Factor	Supplementary Energy
1 (2000)	200 MW	1403 GWh/yr	80%	22 GWh/mth
2 (2001)	400 MW	2805 GWh/yr	80%	44 GWh/mth
3 (2002)	800 MW	4295 GWh/yr	61%	88 GWh/mth
4 - 18 (2003-2018)	1000 MW	5698 GWh/yr	65%	110 GWh/mth
19 - 20 (2018-2020)	800 MW	4558 GWh/yr	65%	88 GWh/mth
21 (2020)	600 MW	3419 GWh/yr	65%	66 GWh/mth
22 (2021)	400 MW	2279 GWh/yr	65%	44 GWh/mth

The following can therefore be calculated:

The total firm energy included in the contract	108,652 GWh/yr
The total supplemental energy included in the contract	25,080 GWh/yr
The total revenue, from firm energy sales, in current dollars	$13,000 million
The total revenue, from firm energy sales, in 1989 dollars	$1,602 million

Conditions of Service

6.01 Capacity Unavailability

The system participation power is intended to be available at all times to Ontario Hydro with a high degree of assurance. In this regard, it is Manitoba Hydro's intention to plan, develop and subsequently operate its resources so that the capacity unavailability does not exceed 4.25% of the monthly capacity entitlement during the critical winter months, October through March.

6.02 Ontario Hydro Scheduling

Ontario Hydro shall:

a) Have the flexibility to schedule delivery of energy at up to 80% monthly capacity factor.

b) Schedule delivery of energy up to the amount for each contract year.

c) Schedule delivery of energy in any hour at a rate not less than 15% of the capacity for such contract year.

6.03 Manitoba Hydro's Ability to Curtail Availability

If conditions arise which affect Manitoba Hydro's ability to make available or deliver the system participation power, deferred energy and supplemental energy as scheduled by Ontario Hydro, Manitoba Hydro may curtail availability and deliveries by the amount necessary to enable Manitoba Hydro to meet:

a) Firm commitments to customers within Manitoba.

b) The 500 MW sale to Northern States Power as set out in the original June 14, 1984 Power Agreement between Northern States Power Company, Manitoba Hydro and the Manitoba Energy Authority.

c) The Island Falls Power and Energy Transfer Agreement between Manitoba Hydro and Saskatchewan Power Corporation dated January 15, 1985.

d) The original August 28, 1987 Electricity Sale Agreement between Manitoba Hydro, the Manitoba Energy Authority and Ontario Hydro.

e) The original November 16, 1987 Diversity Exchange Agreement between Northern States Power Company and Manitoba Hydro.

6.04 Capacity Unavailability Greater Than 4.25%

If Manitoba Hydro curtails scheduled capacity deliveries such that capacity unavailability exceeds 4.25%, the capacity charge to Ontario Hydro will be reduced for that month. However, the total reduction for any given month shall not exceed the monthly capacity charge for that month.

6.05 Curtailment Due to Low Flow Conditions

In the event that Manitoba Hydro forecasts low flow conditions in any month, Manitoba Hydro may curtail the energy, and/or (subject to Section 6.08) curtail the deferred energy to be delivered to Ontario Hydro in such month to the lesser of:

a) The level permitted under Section 6.03 (above).

- or -

b) The level that results from a curtailment equal to the lesser of:

    i) the amount of energy necessary to avoid low flow conditions.

    ii) the amount which would reduce deliveries to 50% monthly capacity factor for such month.

6.06 Deferred Energy

Deferred Energy shall be determined at the end of each contract year and shall be the lesser of:

a) The energy scheduled by Ontario Hydro but curtailed by Manitoba Hydro.

b) The energy not delivered in such contract year.

Ontario Hydro shall not be obligated to purchase or schedule deliveries of Deferred Energy and Ontario Hydro's obligation to purchase energy in such contact year is reduced by the amount of Deferred Energy in such contract year.

6.07 Right to Schedule Deferred Energy

Ontario Hydro has the right to schedule delivery of deferred energy from a contract year within the 60 month period after the end of such contract year.

6.10 Curtailment of System Participation Power
If Manitoba Hydro curtails availability or delivery of system participation power to Ontario Hydro, Manitoba Hydro shall exercise its best efforts to find alternate sources of capacity and energy in excess of Manitoba Hydro's requirements for Ontario Hydro through purchase arrangements if available.

Schedule of Rates

8.01 Monthly Capacity Charge

Ontario Hydro shall pay a monthly capacity charge to Manitoba Hydro which is established at the beginning of each year and is based on:

a) The capacity contracted for in each month.

b) The capital cost of each kW of capacity ($1,727/kW) amortized over 40 years.

The capital cost is adjusted at the beginning of each year by the Hydro Electric Generating Station Construction Price Index. The interest rate is based on Manitoba Hydro's bond yield rates for public debt issues in Canada.

Both the capacity charge and the energy charge are multiplied by the "F" factor. This factor is equal to 1.3 for the first five contract years, 1.0 for contract years six to twelve and 0.75 for contract years thirteen to twenty-two. The "F" factor is designed to ensure that the capital costs of Conawapa do not adversely effect Manitoba Hydro customers' rates.

8.02 Monthly Energy Charge

Ontario Hydro shall pay a monthly energy charge based on a monthly energy rate of $22.10 per MWh adjusted monthly to the Consumer Price Index. This rate also applies to deferred energy.

8.03 Take or Pay Provision

In respect of each contract year, Ontario Hydro shall pay Manitoba Hydro for the capacity and energy whether or not such capacity is used or such energy is scheduled for delivery. At the end of each contract year, if the scheduled energy is less than the contracted energy, Ontario Hydro must pay an additional amount based upon the average of the monthly energy rate for the contract year.

10.05 Supplemental Energy Charge

The supplemental energy charge is $18.00 per MWh adjusted monthly by the Consumer Price Index. This charge is not affected by the "F" factor.

Approvals

11.01 Best Efforts to Obtain Approvals

Each party shall use its best efforts to expeditiously obtain any and all Orders in Council, approvals, licences, permits, permission, consents, certificates and orders ("the approvals") required to be able to carry out the design, construction, development, operation and maintenance of its portion of the facilities required to deliver and receive the system participation power.

11.02 Reporting Deadline for Manitoba Public Utilities Board

This Agreement is subject to the condition that, on or before December 31, 1990, the Manitoba Public Utilities Board issues recommendations in form and content acceptable to Manitoba Hydro. If the recommendations are not favourable to Manitoba Hydro, Manitoba Hydro has the option to terminate this Agreement and the Facilities Agreement effective December 31, 1990. Each party shall be responsible only for its own costs to that date.

11.03 Environmental Assessment of Ontario Hydro Transmission Line

If the environmental assessment of the Ontario transmission facilities required to receive the system participation power is not accepted and approved by December 31, 1990 in form and content acceptable to Ontario Hydro, Ontario Hydro has the option to terminate this Agreement and the Facilities Agreement effective December 31, 1990. Each party shall be responsible only for its own costs to that date.

11.04 Termination Costs

If any of the approvals is not obtained on or before December 31, 1990, the party ("terminating party") who sought and has not obtained the approval may give notice of the termination of this Agreement. The other party shall supply to the terminating party a certificate detailing the costs incurred up to the date of receipt of the termination notice. Within thirty days after receipt of the certificate, the terminating party shall pay to the other party the lesser of:

a) The aggregate amount of the costs shown by the certificate.

- or -

b) The amount set out in the tables on the following page.

Ontario Hydro Termination Costs
(in Millions of Dollars)

Date Notice Given by Ontario Hydro	Amount Payable by Ontario Hydro to Manitoba Hydro
Between January 1 and March 31, 1991	$ 60
Between April 1 and June 30, 1991	100
Between July 1 and September 30, 1991	200
Between October 1 and December 31, 1991	215
Between January 1 and March 31, 1992	230
Between April 1 and June 30, 1992	260
Between July 1 and September 30, 1992	300
Between October 1 and December 31, 1992	315
Between January 1 and March 31, 1993	355
Between April 1 and June 30, 1993	430
Between July 1 and September 30, 1993	535
Between October 1 and December 31, 1993	575
On or after January 1, 1994	575

Manitoba Hydro Termination Costs
(in Millions of Dollars)

Date Notice Given by Manitoba Hydro	Amount Payable by Manitoba Hydro to Ontario Hydro
Between January 1 and March 31, 1991	$ 20
Between April 1 and June 30, 1991	30
Between July 1 and September 30, 1991	40
Between October 1 and December 31, 1991	50
Between January 1 and March 31, 1992	60
Between April 1 and June 30, 1992	70
Between July 1 and September 30, 1992	75
Between October 1 and December 31, 1992	80
Between January 1 and March 31, 1993	85
Between April 1 and June 30, 1993	90
Between July 1 and September 30, 1993	95
Between October 1 and December 31, 1993	100
On or After January 1, 1994	100

Dispute Resolution

12.01 Arbitration and Litigation of Disputes

If any dispute arises in respect of this Agreement which the parties cannot resolve, the parties may agree to submit the dispute for arbitration, or if the parties fail to so agree, the dispute will be litigated in the Court of Queen's Bench for the Province of Manitoba.

General

13.01 Approval of Lieutenant Governor in Council of Ontario and Manitoba

This Agreement is subject to Ontario Hydro and Manitoba Hydro each obtaining the approval of the Lieutenant Governor in Council of its respective province, on or before January 31, 1990, to enter into this Agreement.

13.04 Force Majeure Provision

If either party is unable to meet its obligations pursuant to this Agreement or the Facilities Agreement by reason of accident to its works, explosion, fire, flood, epidemic, war, riot, civil disturbance, wilful destruction of property, labour disturbance, vandalism, malicious acts, failure of equipment, Act of God or the public enemy, or other cause of like nature reasonably beyond the control of such party, then such party shall be excused from the performance of such obligation for as long as the cause of the inability to perform continues. Such party shall not be liable for any penalty, loss or damage caused by or resulting from such inability to perform.

The Facilities Agreement

The Facilities Agreement is also one of the "recent agreements" reviewed by the Board and referred to in Order in Council No. 177/90.

The Facilities Agreement was concurrently executed with the System Participation Agreement and is included in this Report as Appendix XVI.

The Facilities Agreement provides for new interconnection facilities to be put in place by Manitoba Hydro in Manitoba and by Ontario Hydro in Ontario, to facilitate the delivery of the electricity included in the System Participation Agreement.

Specifically, the new interconnection facilities are to include a single circuit overhead 500 kV, 60 Hz alternating current transmission line, together with any equipment associated with reactive compensation, communications, protection, metering, monitoring and contact and other associated equipment. This 500 kV transmission line is in addition to the existing 230 kV interconnections across the Manitoba - Ontario interprovincial boundary.

Manitoba Hydro is to construct, place in service and maintain that portion of its facilities which, in its sole discretion, is required for the delivery of no less than 1500 MW to the point of interconnection.

Similarly, Ontario Hydro is to construct, place in service and maintain that portion of its facilities which, in its sole discretion, is required to receive no less than 1500 MW from the point of interconnection.

Each party is to ensure that its portion of the new interconnection facilities are ready for service on or before November 1, 2000.

Each party is responsible for all costs of the new interconnection facilities located in their respective province.

The Facilities Agreement is only in full force and effect as long as the System Participation Agreement continues in full force and effect.

Position of Independent Witnesses and Intervenors

Having summarized above the salient terms and conditions of the System Participation Agreement, attention must now be turned to a number of issues, directly related to the contractual terms and conditions, that have been raised, primarily by WRA, suggesting that certain provisions of the System Participation Agreement are ambiguous or unfavourable to Manitoba Hydro. These concerns are dealt with below.

WRA

1) WRA was of the view that the scheduling priority allowed:

> "... Ontario Hydro to schedule very little firm energy, to take no supplemental energy at all and to force, by virtue of its contract of half the export capacity of Manitoba Hydro, to force low cost sales at the non-firm rate, and this of course is a problem which is not unique to the contract, it will persist after the contract terminates if no substantial transmission additions are made..."
>
> (Transcript, Volume 12, page 2759)

Manitoba Hydro dealt with the concern raised by WRA, explaining how the scheduling would work under the contract and indicating that there was not an economic problem.

Mr. Thompson explained,

> "In terms of the system participation power, it's a take-or-pay arrangement, so the 65% capacity factor energy, Ontario Hydro has to take it or end up paying for it if they don't, so there is really no flexibility for them to be scheduling on a basis that results in creating uneconomic situations for Manitoba."

(Transcript, Volume 15, pages 3545-3546)

2) WRA also suggested that a dispute may arise in the future because of the possible ambiguity contained in Section 5.02 of the System Participation Agreement which requires each party to use their best efforts to minimize the extent to which failures on one system adversely affect the other system, and provisions related to force majeure, which attach importance to the origin of the force majeure event.

WRA was concerned that the wording created a "circularity" and would cause a problem if, for example, a problem arose on the Ontario side of the border which precipitated a force majeure event, or an event for which Manitoba is responsible on its side of the border.

Manitoba Hydro disagreed with WRA and took the position that although a force majeure situation is, by definition, a rare event, it would be quite clear as to in which jurisdiction the problem originated. If there was a disagreement as to which party was responsible for the problem, Manitoba Hydro would rely on the dispute resolution clauses in the System Participation Agreement.

3) WRA also raised concern as to whether the System Participation Agreement was clear in respect to the amount of deliveries that can be reduced under low flow conditions.

Manitoba Hydro indicated that under low flow conditions, Manitoba Hydro can curtail deliveries to Ontario Hydro from the 65% capacity factor level to a 50% capacity factor level.

4) WRA and GWC raised the concern that revenues from the System Participation Agreement may be reduced due to either low flow or unavailability of power to serve the sale requirements.

Manitoba Hydro answered this concern by indicating there is no opportunity for Ontario Hydro to avoid paying the 65% capacity factor energy. This is part of the take-or-pay arrangement in the agreement.

Manitoba Hydro also testified that deferred energy can be created by Manitoba Hydro under low flow conditions if it is of benefit in maintaining service in Manitoba. Furthermore, under a condition of force majeure in Ontario, deferred energy can be created, but Ontario Hydro is not relieved of its obligation to take-or-pay.

As to the concern that there may be a revenue loss from the unavailability greater than 4.25%, Mr. Thompson advised:

> "We are satisfied that the probability of exceeding the 4.25% allowance would be less than 3% and if one makes the extreme assumption that the maximum 3% occurs and the full 1,000 megawatts is unavailable at these times and each such unavailability exceeds the minimum 30 minute duration, then the revenue from the sale to Ontario Hydro, the total revenue in terms of discounted 1990 dollars, would be reduced by $24 million."
>
> (Transcript, Volume 19, page 4313)

Manitoba Hydro concluded that the probability and severity of these situations arising are sufficiently low that they are not to be taken as a cause for concern.

Manitoba Hydro also concluded in its final argument that the contract terms are clear and that the risks are appropriately shared between the parties.

An additional concern that WRA raised with respect to the terms and conditions of the System Participation Agreement was the omission of a term or condition that would permit Manitoba Hydro to "wheel power" across Ontario Hydro's transmission facilities to a third party. WRA believed that the upside potential of such wheeling would be the opportunity for Manitoba Hydro to sell its electricity to the north-eastern United States at substantially higher prices than the price available in Manitoba Hydro's current export market.

In response to this concern, Manitoba Hydro testified that there was a downside in that Ontario Hydro would, by such a wheeling agreement, be allowed access through Manitoba Hydro's transmission facilities to markets in Saskatchewan or the United States that are interconnected with Manitoba. Therefore, Ontario Hydro would be in competition with Manitoba Hydro in Manitoba Hydro's existing export market.

WRA and Manitoba Hydro agreed that if wheeling is of a mutual benefit to the parties, then it becomes a matter that can be negotiated and included in a subsequent agreement at any time. WRA also agreed that the absence of any terms and conditions respecting wheeling, does not affect the benefits that presently exist in the System Participation Agreement.

Board Findings

After having reviewed the evidence from Manitoba Hydro and the intervenors' witnesses and the independent witnesses, the Board finds the terms and conditions of the System Participation Agreement to be sufficiently clear and unambiguous.

The specific concerns raised in respect of the wording of the System Participation Agreement have been met by Manitoba Hydro. However, out of an abundance of caution, Manitoba Hydro may wish to follow WRA's suggestion of "an exchange of letters" to further ensure no future concerns arise in the interpretation of certain terms and conditions.

As WRA noted:

> "The parties to the contract in my experience know exactly what they mean, but the parties to the contract aren't always available five or ten years down the road, the people who negotiated it are not always available five to ten years down the road when a dispute erupts, and where we have obvious ability here to avoid these ambiguities and to express intent, we should take them."

(Transcript, Volume 12, page 2763)

The Board is not prepared to find the System Participation Agreement deficient because it is silent on the concept of Manitoba Hydro "wheeling" its power across Ontario Hydro's transmission facilities to a third party. While wheeling is seldom done in Canada, it is evident that there are higher prices available for electricity on the Eastern seaboard, than would be available from other utilities such as Northern States Power and United Power Association.

During its ongoing relationship with Ontario Hydro, Manitoba Hydro should further investigate a wheeling arrangement if it appears feasible as well as beneficial to both parties.

WRA and Manitoba Hydro agreed that if wheeling is of mutual benefit to the parties, it becomes a matter that can be negotiated and included in a subsequent agreement at any time. WRA also agreed that the absence of any terms and conditions respecting wheeling does not affect the benefits that presently exist under the System Participation Agreement.

The issue of whether it is advisable to enter into a sale agreement with Ontario Hydro at this or any other time is considered in the following sections which address the expected benefits and inherent risks of Manitoba Hydro's Preferred Development Plan.

No issue was taken with the terms and conditions of the Facilities Agreement.
The Facilities Agreement is only required if the System Participation Agreement proceeds, and therefore is left to be considered as part of the System Participation Agreement in the subsequent sections.

Diversity Exchange Agreements

Pursuant to paragraph 1 (b) of Order in Council No. 177/90, the Board reviewed the agreements signed November 20, 1989 between Manitoba Hydro and Northern States Power (NSP) and United Power Association (UPA) for diversity exchanges commencing in 1995.

Under these diversity exchange agreements, Manitoba Hydro will make 150 MW available to each of the U.S. utilities during the summer months from May 1 to October 31 in each year from 1995 until 2015. During the same years, the two U.S. utilities will each make 150 MW available to Manitoba Hydro during the winter months of November 1 to April 30.

Also on November 20, 1989, Manitoba Hydro, NSP and UPA entered into:

1) A Facilities Agreement relating to the construction of new transmission facilities required for the diversity exchange agreements.

2) A Co-ordination Agreement relating to the operation of the facilities in a co-ordinated manner.

Copies of the two diversity exchange agreements, the Facilities Agreement and the Co-ordination Agreement, are located in Appendix VIII of Manitoba Hydro's Submission).

Manitoba Hydro believes the diversity exchanges are advantageous because they defer the construction of new generating plants.

> "The major advantage of the seasonal diversity transaction (sic) is that they allow Manitoba Hydro to import power from U.S. utilities in the winter months when our peak power requirements are the greatest, and export power during the summer months when U.S. Utilities' peak power requirements are the greatest. North/South diversity transactions of this nature truly are win/win situations for both the seller and the buyer because they defer the construction of a plant that would otherwise be required to supply the system peaks of their respective utilities."

(Transcript, Volume 1, page 82)

The net long-term benefit of these diversity exchange agreements was quantified at $138 million (1989 present value) by Manitoba Hydro. (Manitoba Hydro's Submission)

Position of Independent Witnesses and Intervenors

In a rare showing of unanimity, those intervenors taking a position on the diversity exchange agreements endorsed the agreements as making "obvious sense"... (CAC/MSOS, Written Argument, page 72), and "as a likely component of a least cost program for satisfying the energy needs of Manitoba consumers." (CSC, Written Argument, page 5.)

MIPUG and NFC also endorsed the diversity exchange agreements.

However, the Board notes with some concern, that while the diversity agreements have been executed, they remain conditional, pending receipt of certain regulatory approval.

Mr. Lambert testified that the Exchange Agreements still require the approval of the Administrator (or designee) of the Minnesota Rural Electrification Administration. This approval is only required by UPA for its financing requirements if a new 230 KV, 60 hertz A.C. transmission line is constructed. Discussions are presently ongoing between Manitoba Hydro and UPA as to whether a new transmission line need be built or whether the existing transmission facilities can be upgraded to accommodate the diversity exchanges. The conclusion of these discussions will determine whether the approval of the Administrator of the Minnesota Rural Electrification Administration will still be required. Although this approval was to be obtained prior to September 30, 1990, this date was extended until March 1, 1991 by agreement of the parties.

An approval, yet to be obtained by Manitoba Hydro for the diversity agreements, is that of the National Energy Board (NEB). This approval is under the new relaxed rules of the NEB which do not necessarily require a hearing.

The diversity exchange agreements are included in the initiatives that Manitoba Hydro has relied on to delay for one year, the construction of a major generating station (i.e., Conawapa or Wuskwatim from 1999 to 2000).

In the various submissions to the Board, Manitoba Hydro and the intervenors assumed that the diversity exchange agreements will in fact be implemented. If they are not implemented, there will be a negative effect on the development plans of Manitoba Hydro.

The Board, in raising this concern, expects Manitoba Hydro to use its best efforts to obtain the requisite approvals in a timely fashion to allow the diversity exchange agreements to be fully implemented.

Board Findings

The Board finds the diversity exchange agreements with NSP and UPA, together with any related improvements to the transmission capability with Minnesota, as reasonable and appropriate initiatives for Manitoba Hydro to proceed with at this time.

The Board also encourages Manitoba Hydro to seek out further diversity exchange agreements where feasible and cost-effective.

Evaluation of Key Scenarios

In the preceding sections, the Board, in its findings, has accepted the following:

1) The planning criteria and guidelines used by Manitoba Hydro in the section entitled, "The Present System";

2) Manitoba Hydro's load forecast reviewed in the section entitled, "Load Forecast";

3) The demand-side management and supply options discussed in the section entitled, "Meeting the Load Forecast";

4) Manitoba Hydro's Sequence 1 and 2 as the remaining feasible alternatives under the section entitled, "Manitoba Hydro's Alternative Supply Scenarios";

As a consequence, this section and the one following are of vital importance in the Board's recommendation as to the next generation facility.

Pursuant to 1 (c) and (d) (iii) of Order in Council 177/90, the Board is directed to consider the effect of the proposed capital projects on the electricity rates to be charged to Manitoba consumers and to ensure that the proposed capital projects have been selected on reasonable grounds (i.e., technical feasibility, cost efficiency and reliability). The following discussion will focus on comparisons between Manitoba Hydro's Scenarios 1 and 2. These comparisons are categorized as economic, socio-economic, environmental and financial evaluations.

Economic Evaluation

The table on the following page provides a comparison of the long-term sequence economics associated with each of the scenarios.

All revenues and costs in the tabulation are discounted to 1989 using an effective discount rate of 5.25% per year. This rate is derived from Manitoba Hydro's projected inflation rate of 5% and long-term interest rate of 10.5%.

Cost components include generating plants and associated transmission, capital costs, production costs, interconnection capital costs, Winnipeg-Brandon transmission costs and demand-side management costs. Production costs include plant operating and maintenance costs, thermal and import costs, water rentals, minus revenue from non-firm export transactions. Demand-side management costs are based on an assumed program cost of 2¢/KW/h.

Total costs of Scenario 1 versus Scenario 2 are $2,670 million and $1,764 million, respectively. Revenues from the Diversity and Ontario Sale firm transactions total $1,653 million and $51 million for Scenarios 1 and 2, respectively. The net cost of Scenario 1 totals $1,017 million compared to a net cost of $1,713 million for Scenario 2. The cost difference of $696 million between the two sequences represents the net benefit of Manitoba Hydro's Preferred Development Plan.

Economic Comparison Between Scenario 1 and Scenario 2
In Millions of 1989 Present Value Dollars
at a 5.25% Discount Rate

	Scenario 1	Scenario 2	$ Difference
Present Value of Cost Components			
Generation/Transmission Capital Costs	$2,169	$1,297	$ 872
Production Costs	247	276	(29)
Interconnection Capital Costs			
NSP/UPA 300 Diversity	15	15	-
Ontario 1,000 Sale	63	-	63
Winnipeg-Brandon Transmission	47	47	-
DSM Costs	129	129	-
Total Costs	2,670	1,764	906
Present Value of Revenue from Firm Transactions			
NSP/UPA 300 Diversity	51	51	-
Ontario 1,000 Sale	1,602	-	1,602
Total Firm Revenue	1,653	51	1,602
Net Cost	$1,017	$1,713	$ 696

In summary, Scenario 2 is more costly than Scenario 1 by $696 million because the loss of the Ontario Sale revenue ($1602 million) plus the increase in system production costs ($29 million) are greater than the capital cost savings due to the deferral of plant without the Ontario Sale ($872 million) and the elimination of the need for the Ontario tie line ($63 million).

The Board notes that the $696 net benefit of the Preferred Development Plan was later recalculated by Manitoba Hydro using a higher discount rate of 5.5% to incorporate the cost of the debt guarantee fee charged by the Province. The net benefit, using the 5.5% discount rate, amounted to $656 million also in 1989 present value dollars.

During the public hearing, various intervenors raised the question of whether the Ontario Sale would still be as beneficial without the other three initiatives proposed under Manitoba Hydro's Preferred Development Plan (i.e., the 300 MW NSP/UPA diversity exchange, thermal plant life assurance and the 100 MW demand-side management target). Therefore, the Board felt it was necessary to evaluate the direct benefits of the Ontario Sale which is presented in the following section.

Board Evaluation of the Direct Benefits of the Ontario Sale

In order to meet the capacity requirement of the 1,000 MW Ontario Hydro firm power sale, additional generation has to be developed. The Conawapa generating station and associated transmission would be the logical choice since it would provide sufficient capacity and energy. There was considerable debate during the hearing concerning the potential benefits of the Ontario Sale. The Board deemed it informative to compare the revenues from the Ontario Sale with that portion of the plant costs that directly relate to these revenues for this purpose.

Manitoba Hydro had testified that the Ontario Sale is a system participation sale as opposed to a plant participation sale and was therefore reluctant to separate the net benefits of the Ontario Sale from the net benefits of its Preferred Development Plan. However, the Board considers this matter to be of sufficient importance that the revenues and expenses directly associated with the Ontario Sale should be matched in order to demonstrate the approximate direct benefits of the Ontario Sale.

The following assumptions were used to calculate the direct benefits of the Ontario Sale:

1) In keeping with Manitoba Hydro's Submission and other data presented, the benefits are calculated in 1989 present value dollars. The interest rate is 10.75%, which consists of Manitoba Hydro's 10.50% cost of debt plus 25 basis points for the value of the provincial guarantee fee. At a 5% inflation rate, the interest rate was then converted into a 5.50% real discount rate which was used to present value all the costs and revenues to 1989.

2) The benefits are based on constant dollar costs derived from information provided by Manitoba Hydro, which includes water rental costs currently in effect along with plant operating and overhead costs.

3) The Conawapa generating station will be made up of 10 generating units which will come into service as they are completed over a two-year period, commencing in 2000. The costs of the plant are capitalized over the period in which the generating units come into service. The Ontario Hydro sale is imposed on the plant in steps coinciding with the rate at which the generating units come into service commencing on November 1, 2000. The full capacity requirement is not imposed on the system until November 1, 2003, when all units become operational. As a result, the sale offsets the cost at each step and surplus capacity is kept to a minimum.

4) Regarding the depreciation period, hydro-electric plants have a life expectancy of 65 years but, according to Manitoba Hydro, can be expected to last 100 years. For the purposes of this calculation, the capital recovery factor or the fixed cost ratio was determined based on a 65-year life. The capital recovery of transmission systems are based on a 45-year life which approximates their expected useful life.

5) Capacity allocation factors were established based on the ratio of capacity required for the sale and the summer capacity of the plant when each step of the sale commences. These factors were used to determine the portion of the capital costs which can be attributed to the Ontario Sale each year. Energy allocation factors, based on the ratio of energy required for the sale and the average energy output of the plant, were prepared to determine the amount of operating and overhead costs attributable to the Ontario Sale. Water rental costs were determined based on the amount of energy required for the Ontario Sale.

6) The Ontario Sale revenue is derived from the firm capacity and energy made available under the contract terms. The capacity charge is determined using the construction cost of Conawapa ($1,727 per KW in 1988 dollars escalated to a 1989 current dollar base). The amount for each contract year is then determined using a 40-year recovery, as outlined in the contract, at 10.5% interest and present valued to 1989. The energy charge was determined by the energy contracted each year at $22.10 per MW.h (in 1988 dollars) present valued to 1989.

The final results of the analysis in 1989 present value dollars are as follows:

Direct Benefits of the Ontario Sale

Revenue	
Capacity	$ 736.0 million
Energy	788.5 million
Total revenue	1,524.5
Costs	
Debt charges	927.1
Water rental	63.9
Operation and overhead	65.5
Total costs	1,056.5
The direct benefit of the Ontario Sale in 1989 dollars	$ 468.0 million

In summary, the direct benefits of the Ontario Sale amount to $468 million (in 1989 present value dollars). The difference between this figure and the $696 million (in 1989 present value dollars) net benefits of Manitoba Hydro's Preferred Development Plan arises from the indirect benefits of the Preferred Development Plan. These indirect benefits include enhanced system reliability, supplementary energy sales and higher prices for surplus energy sales.

The calculations used in determining these results may be found in Appendix XIV.

CAC/MSOS also prepared its own calculation of the direct benefits of the Ontario Sale. It allocated the costs associated with the Ontario Sale to Conawapa as well as to other hydro-electric plants as they came into service. The results of CAC/MSOS' analysis indicated that the net benefit of the Ontario Sale is $1,539 million in 1990 current dollars, excluding any additional revenue from the sale of any supplemental or surplus energy. In addition, CAC/MSOS did not take system losses into consideration. If system losses had been included in its calculation, the net benefits of the Ontario Sale would be reduced to $1,231 million in 1990 current dollars. CAC/MSOS' analysis was filed as Exhibit #CAC/MSOS-8 during the public hearing and is included in Appendix XV.

The CAC/MSOS calculation, if converted to present value dollars, would be in the same order of magnitude as the Board's calculation.

Socio-Economic Evaluation

Socio-economic evaluation is a planning tool used by governments to evaluate projects from a broad federal or provincial perspective, taking into consideration, for example, the employment, tax and natural resource impacts.

Various intervenors noted that the socio-economic impacts related to Manitoba Hydro's preferred development plan are primarily timing differences to the extent that such impacts are accelerated. In particular, the Northern Flood Committee noted that the Board's decision whether or not to recommend Manitoba Hydro's Preferred Development Plan will not turn on the social cost benefit analysis. Manitoba Hydro also came to a similar conclusion. During the public hearing, Mr. Brennan testified that socio-economic impacts were not one of the primary criteria used by Manitoba Hydro in selecting its Preferred Development Plan (Transcript, Volume 6, page 1269).

The Board, although it notes the results of Manitoba Hydro's socio-economic evaluation as presented on the following pages, concurs with the view that such an analysis is outside its terms of reference as provided in Order in Council No. 177/90. Although the results of the socio-economic evaluation are important from a governmental perspective, these results will not influence the Board's decision on the next generation decision.

The results of the social benefit-cost and economic impact analysis prepared for Manitoba Hydro by Marvin Schaffer & Associates Ltd. entitled, "Benefit Cost and Economic Impact Analysis of Manitoba Hydro's Preferred and Alternative Generation Expansion Plans", (March 1990) are summarized below for information purposes.

Manitoba Hydro's social benefit-cost analysis was used to calculate the social net costs of each alternative plan. It was assumed that the value of the domestic output is the same for each of the expansion plans. Consequently, differences in net benefits among the expansion plans can only be due to differences in net costs. The expansion plan with the lowest social net costs is the one which offers the greatest social net benefits.

The calculation of net costs was done by adjusting the forecast expenditures facing Manitoba Hydro to take into account differences between costs from a private or Manitoba Hydro perspective and costs from a social or broad provincial perspective. Specifically, labour costs were adjusted to take into account the probability that some of the persons hired would otherwise be unemployed. Also, water rental and provincial sales taxes were excluded from the social costs because they represent a government transfer as opposed to a real cost from a provincial perspective. No adjustments were made for natural resource and environmental costs.

The following tables summarize the social net cost using 6% and 8% real discount rates. These rates were selected to reflect a reasonable range of the social opportunity cost of capital from a provincial perspective. The Preferred Development Plan exhibits lower social net costs than Scenario 2 at an 8% and 6% discount rates.

Social Net Cost Results
(Present Value at 6% Real Discount Rate in $1989 millions)

	Preferred Development Plan	**Scenario 2**
Private Net Costs*	711.6	1,228.6
Labour Adj.	(168.0)	(97.3)
Water Rental Adj.	(707.0)	(649.0)
Tax Adj.	(80.8)	(44.7)
Social Net Costs**	(244.0)	437.6

* Excludes existing hydro O&M costs.
** Negative net costs occur when the export revenues exceed the cost of construction and operating the facilities for both the export and domestic load.

Social Net Cost Results
(Present Value at 8% Real Discount Rate in $1989 millions)

	Preferred Development Plan	**Scenario 2**
Private Net Costs*	887.2	1,025.2
Labour Adj.	(141.3)	(76.6)
Water Rental Adj.	(519.0)	(480.1)
Tax Adj.	(69.2)	(35.9)
Social Net Costs**	157.6	432.6

* Excludes existing hydro O&M costs.
** Negative net costs occur when the export revenues exceed the cost of construction and operating the facilities for both the export and domestic load.

By comparing the export revenue and costs of the preferred plan with Scenario 2, the incremental revenues, expenditures, and net benefits of each planning initiative can be identified. In the next table, the relative socio-economic benefits of the Preferred Development Plan are summarized. All of the initiatives inherent in the preferred plan, except for Thermal Life Assurance at a 6% rate, offer net benefits. The Ontario Sale and the diversity benefits are quite large, even more so when combined.

Net Socio-Economic Benefits of Preferred Development Plan Compared to Scenario 2
(Base Case Present Value in $1989 millions)

	Preferred Development Plan	Scenario 2
6% Discount Rate		
Incremental Rev.	1,506.9	(67.5)
Incremental Exp.	825.3	(175.1)
Net Benefits of Preferred Plan	681.7	107.5
8% Discount Rate		
Incremental Rev.	1,032.9	(47.4)
Incremental Exp.	757.9	(191.4)
Net Benefits of Preferred Plan	275.0	144.0

The economic impact analysis indicates the income and employment that will be directly and indirectly generated as a result of the construction and operation of the different projects in Scenarios 1 and 2.

The construction-related impacts are much greater than the operating impact. The largest construction-related impacts will be generated by Conawapa, because of the large amount of expenditures this project entails. Generally, both projects generate similar impacts per dollar of expenditure.

The Preferred Development Plan starts with Conawapa first and thus will generate significant income and employment impacts over the 1990-1999 period. The Preferred Development Plan will generate an estimated $900 million income and 20,000 person years of employment in Manitoba over that period.

Environmental Evaluation

The environmental evaluation consists of a qualitative comparison of potentially significant environmental issues associated with the two first plant alternatives, Conawapa and Wuskwatim. Allowances of $53 million and $42 million for Conawapa and Wuskwatim have been internalized in Manitoba Hydro's project costs as the appropriate environmental costs. Potentially significant environmental issues of the Conawapa and Wuskwatim projects are identified and summarized in the following table.

Potentially Significant Environmental Issues of the Conawapa and Wuskwatim Projects

Categories of Potential Issues	Conawapa Project		Wuskwatim Project	
	Generating Station (4 sq. km of flooding)	Transmission Lines/Stations (over 600 km)	Generating Station (127 sq. km of flooding)	Transmission Lines/Stations (over 600 km)
Public Health and Safety		- Electric and magnetic fields (EMF) - Proximity of Riel Station to Deacon water reservoir	- Mercury methylation due to flooding raises issue of elevated mercury in domestic fish resources - Free and normal use of Burntwood River for Nelson House and Thompson residents with added flooding and downstream water flow and level fluctuation	- Electric and magnetic fields (EMF)
Disruption of Livelihood and Way of Life			- Effects on Nelson House trapping, fishing and hunting	
Disruption of Important and Scarce Resources	- Impacts on brook trout population in Nelson River due to obstructing fish migration - Increased access to Nelson River estuary and Hudson Bay Coast	- Impacts on caribou, provincial parks and large wilderness area on east side of Lake Winnipeg		- Effects on Grassie River Provincial Park
Long Term, Low Level Environmental Effects		- Visual impact of major new transmission line on wilderness with new river and stream crossings - Potential effects on agricultural activity		- Visual impact of several new transmission lines on wilderness with new river and stream crossings
Relocation of Infrastructure Required			- Downstream water fluctuations may require relocation of Thompson Float Plane Base Cemetery at Wuskwatim Lake	

During the hearing, Mr. Lambert noted that the amount of flooding caused by the Conawapa project versus the Wuskwatim project was the major difference in environmental impacts:

> ". . . the generating station itself (Conawapa) would result in four square kilometers of flooding along the Nelson River and the transmission would involve construction of 800 kilometers of high voltage DC transmission down the east side of Lake Winnipeg.
>
> For the Wuskwatim project, the generating station itself would involve 127 square kilometers of flooding and transmission lines which would be built in the north country, and they would be of the high voltage AC type, but there's also 600 kilometers of AC transmission associated with that project.
>
> With the Wuskwatim site and the extra flooding, there is the mercury problem which arises, and of course the proximity of that site to the Nelson House and Thompson communities has extra significance."

(Transcript, Volume 2, pages 406-407)

In response to concerns raised by various intervenors regarding the potential magnitude of environmental costs, Dr. Shaffer, an expert witness testifying on behalf of Manitoba Hydro, made the following comments:

> "With further environmental impact assessment and research, Manitoba Hydro will be able to develop more refined quantitative estimates of the environmental costs of its projects. However, based on the overview studies and impact assessment work done to date, Manitoba Hydro has no reason to believe that the unquantified costs (in excess of the amounts already included in the capital cost estimates) are anywhere near the estimated net benefits of its preferred development plan. There is certainly no identified impacts that would suggest, as Dr. Fenton did without any supporting evidence, that they could be in the order of the quantified net benefits of the Ontario Sale. Nor is it appropriate to compare, as Mr. Young did without any technical support, the impacts of advancing hydro generation and related transmission projects on the Nelson and Burntwood Rivers with the Churchill River Diversion and Lake Winnipeg Regulation project. A more appropriate comparison would be the impacts of advancing Limestone and other projects for the NSP sale, where the quantified natural resource losses were estimated to be less than $1 million, and development of the Bipole 1 and 2 transmission lines whose post-development mitigation and compensation costs have been minimal.
>
> It should be noted that for the most part, the environmental costs due to the Ontario Sale are the costs of advancing the impacts due to the earlier timing of construction; they are not the costs of the impacts in themselves. This further diminishes their magnitude relative to the quantified net benefits of the sale.
>
> Finally, offsetting any environmental cost of the sale in Manitoba are environmental benefits in Ontario or elsewhere due to the deferment of nuclear,

coal or other imported power for that province. From a global perspective, this is important to consider when evaluating the overall environmental impact of the sale."

(Manitoba Hydro, Rebuttal Evidence, pages 4-5 of Appendix C)

During the non-evidentiary meeting held in Thompson, Manitoba on September 11 and 12, 1990, Mr. Wright, publisher of the Thompson Citizen (which circulates in Thompson) and the Nickel Belt News (which circulates around most of the area under contention, namely Cross Lake, Norway House, Churchill, Gillam, South Indian Lake, Leaf Rapids, and Split Lake) made the following comments regarding the environmental impacts associated with Conawapa during his presentation:

> ". . . the Conawapa project, to my mind, is environmentally clean, it's almost a superstar, because the area where it's to be built, there is not a man, woman, or child living within 50 miles of the banks of the Nelson River where they propose to build the power dam, there will be no flooding on site, the banks are high, the banks are stable, and . . . any environmental damage that is going to occur has already occurred.
>
> . . . I think that if Conawapa doesn't proceed, or some other alternative, I think it's a sad day for Northern Manitoba, because the projects have given us economic life where there was none, they carried us through the years when the mining economy was in the doldrums, they have put hundreds of millions of dollars into the pockets of Northern Manitoba families in the form of wages and benefits, they have built roads where there were no roads, they have put in sewer and water where there was no sewer and water, they have provided line power to all -- most -- the majority of communities in Northern Manitoba that I think otherwise would not have been possible.
>
> The Conawapa project is by far superior, both economically and ecologically, than Wuskwatim, because the only economic way that the Wuskwatim dam can be built calls for more massive flood, which in my own belief will never happen here because the opposition will be so stringent that it will never take place unless it is by Order-in-Council.
>
> I truly believe that of the two options, Conawapa is far superior because it gives a larger power dam for roughly the same dollars that Wuskwatim could cost, there is no environmental damage to my knowledge that I can look at. Wuskwatim, on the other hand, would cause massive environmental damage, cause massive political unrest among the Indian bands, among the City of Thompson."

(Transcript, Volume 16, pages 3647, 3649-50 and 3667-68)

NFC had the following comments regarding Manitoba Hydro's Preferred Development Plan:

> "The NFC opposes in principle the construction of any dams on the Nelson River other than Conawapa, and any dams on the Burntwood River, including specifically Wuskwatim, until broad study is completed on the impact of hydro-electric development on northern ecosystems and aboriginal communities and until and unless there can be general agreement among all parties, including the five Bands of the NFC, concerning the acceptability of Wuskwatim or other like works."
>
> (NFC, Written Argument, pages 11-12)

Manitoba Hydro concluded that environmentally sound measures for siting, designing, constructing and operating the Preferred Development Plan would be undertaken to ensure compliance with environmental standards. Manitoba Hydro states that it is confident that project impacts on people's rights and interests can be addressed within acceptable programs of mitigation and compensation.

During the public hearing, Manitoba Hydro filed Exhibit #MH-3A entitled, "Risk Management and Exposures". This document addressed the following concerns regarding the required environmental reviews and licenses and the implications of a delay in obtaining approvals (pages 13-14):

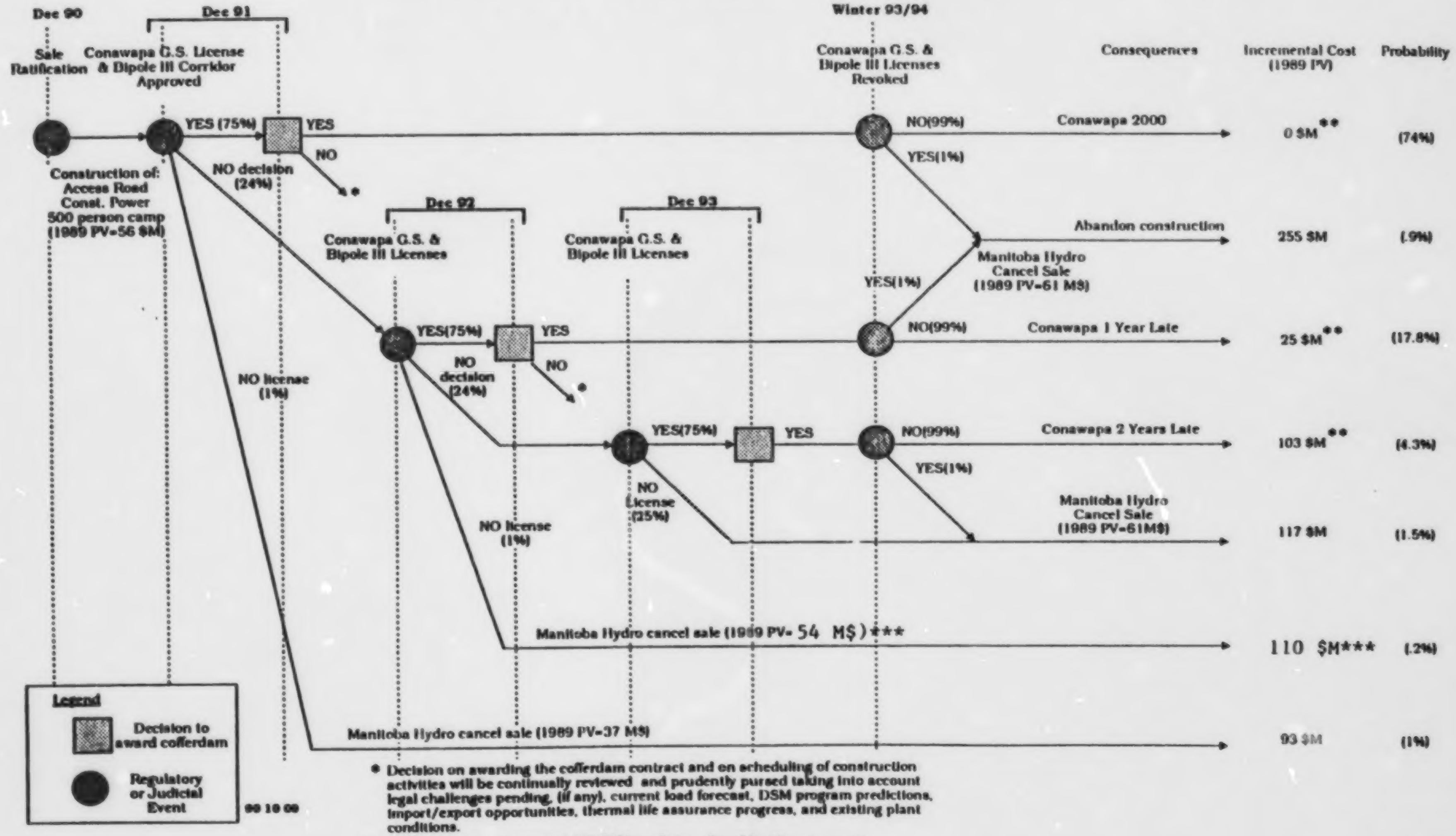
> "There is still some uncertainty as to the responsibilities of and the procedures to be used by both the Federal and Provincial governments in respect of the environmental review and licensing of the proposed projects. In order to minimize its risks here, Manitoba Hydro has engaged expert, independent legal counsel to ensure that all its environmental activities are conducted strictly within the letter of the law. It is also actively assisting the licensing authorities to ensure that the most rigorous and correct standards and procedures are used to test the projects.
>
> Manitoba Hydro has completed sufficient environmental assessment of the proposed Conawapa and Bipole III projects to assure itself that there will not be any effects that could be judged sufficiently severe to cause cancellation.
>
> In respect of the Bipole III and Ontario transmission lines, Manitoba Hydro has commenced one of the more extensive public consultation and site selection processes ever performed in the Province.
>
> The project schedules provide adequate time for the completion of the anticipated, rigorous environmental assessment processes.
>
> Manitoba Hydro has engaged reputable consultants to help assure that all environmental assessment work is performed to the highest possible standard.
>
> All of these activities are undertaken to help ensure that there will be a very low likelihood of delay or denial of the necessary licenses."

On page 32-33 of Risk Management and Exposures, the implications of a delay are discussed:

> "It is possible, however, that because of the current uncertainty surrounding jurisdiction, receipt of environmental licenses could be delayed to the point where Conawapa and/or Bipole III cannot be completed until 2001 or later. The Riel-Ontario border line is not likely to be so delayed because of its relatively short construction period.
>
> Under this condition, and with all other things being as forecast, Manitoba Hydro's obligations under the contract would still commence in 2000, and steps would have to be taken to provide for up to an extra 300 MW of firm capacity in the period 2000-2002. There would be sufficient firm energy available to meet requirements. This short-term capacity would probably be in the form of combustion turbines, life extension of the Brandon 1-4 units, a 'buy-back' from NSP or Ontario Hydro, or purchases from other interconnected utilities, whatever was determined to be practical and economic at the time. The probable net cost in this situation would be in the order of $25 million (1989 present value dollars), still well within the benefits of the preferred development sequence, and the long term rates paid by Manitoba customers would be only marginally increased from 1.1% to 1.2% per year for the 1996-2005 period."

In response to concerns raised over possible delays in obtaining environmental approvals, Manitoba Hydro filed Exhibit #MH-35 entitled, "Environmental Regulatory Related Risks". This exhibit (see following page) detailed the incremental costs associated with delays in awarding the cofferdam contract as well as delays in obtaining licenses for the Conawapa generating station and Bipole III. If Conawapa is one year late due to these regulatory problems, Manitoba Hydro estimates it would reduce the net benefit of $696 million associated with the Ontario Sale by $25 million (in 1989 present value dollars). If Conawapa is two years late, the $696 million would be reduced by $103 million. The worst-case scenario is one in which the Conawapa generating station and Bipole III licenses are revoked in 1993/94 and Manitoba Hydro would thus have to abandon construction. Although this worst case scenario has incremental costs of $255 million (in 1989 present value dollars), the probability of such an event occurring is estimated by Manitoba Hydro to be only .9%.

ENVIRONMENTAL REGULATORY RELATED RISKS
(Estimated probabilities listed in brackets)


Dec 90
Sale Ratification
Dec 91
Conawapa G.S. License & Bipole III Corridor Approved
Construction of: Access Road Const. Power 500 person camp (1989 PV=56 $M)
YES (75%)
YES
NO
**
NO decision (24%)
NO license (1%)
Dec 92
Conawapa G.S. & Bipole III Licenses
YES(75%)
YES
NO
*
NO decision (24%)
NO license (1%)
Dec 93
Conawapa G.S. & Bipole III Licenses
YES(75%)
YES
NO License (25%)
Winter 93/94
Conawapa G.S. & Bipole III Licenses Revoked
NO(99%)
YES(1%)
YES(1%)
NO(99%)
NO(99%)
YES(1%)
Manitoba Hydro Cancel Sale (1989 PV=61 M$)
Manitoba Hydro Cancel Sale (1989 PV=61M$)
Manitoba Hydro cancel sale (1989 PV= 54 M$)***
Manitoba Hydro cancel sale (1989 PV=37 M$)
Consequences
Conawapa 2000
Abandon construction
Conawapa 1 Year Late
Conawapa 2 Years Late
Incremental Cost (1989 PV)
0 $M**
255 $M
25 $M**
103 $M**
117 $M
110 $M***
93 $M
Probability
(74%)
(.9%)
(17.8%)
(4.3%)
(1.5%)
(.2%)
(1%)
Legend
Decision to award cofferdam
Regulatory or Judicial Event
90 10 09

* Decision on awarding the cofferdam contract and on scheduling of construction activities will be continually reviewed and prudently pursed taking into account legal challenges pending, (if any), current load forecast, DSM program predictions, import/export opportunities, thermal life assurance progress, and existing plant conditions.

**Sale proceeds, but expected 696 $M benefit is reduced by these amounts

*** Corrected figures, Transcript, Volume 17, page 3907

Financial Evaluation

Impact on Rates

From a customer perspective, the Preferred Development Plan (Scenario 1) produces the most favourable results. The two alternatives were analyzed to determine their impact on Manitoba Hydro's future financial performance and revenue requirements.

Comparative annual and cumulative rate impacts for Scenarios 1 and 2 are summarized on the following table which shows the weighted average price of power to Manitoba consumers over the 1991 to 2027 period. In the Preferred Development Plan, this price is projected at approximately $22 per MWh (in 1989 present value dollars), a decline of over 30% from today's level of approximately $32 per MWh.

The difference in the present value of the revenue stream between Scenario 1 and Scenario 2 is $441 million (differences between $9,021 million and $9,462 million for Scenarios 1 and 2, respectively). This $441 million represents the amount of savings that will be realized by Manitoba customers from 1991 to 2027 in 1989 present value dollars.

The Board notes that this $441 million savings expressed in 1989 present value dollars is equivalent to $5.1 billion in current dollars over the period 1991 to 2027. In other words, if the Preferred Development Plan is rejected and Manitoba Hydro proceeds with Scenario 2, Manitoba Hydro would have to collect an additional $5.1 billion from consumers rates over the period 1991 to 2027.

Rate Impacts of Scenario 1 vs. Scenario 2
Rates at or Below Inflation

	Scenario 1 Preferred Development Plan	**Scenario 2 No Ontario 1000 MW Sale**
Range of Annual Rate Increases (year ended)		
1996 - 2005	1.1%	2.0%
2006 - 2020	5.0%	5.0%
2021 - 2027	4.0% - 5.0%	5.0%
Present Value of Revenue from Manitoba Hydro Customers (million $1989)		
1991 - 2027	$9,021	$9,462
Weighted Average Price of Power* per MW.h ($1989)		
1991 - 2027	$22.0	$23.5

* Cumulative total of General Consumers revenues divided by cumulative total of MW.h generated for Manitoba firm load per 1989 Load Forecast, modified for DSM reductions where applicable. Projected 1989/90 value is approximately $32.

During the public hearing, Manitoba Hydro filed Exhibit #MH-3C entitled, "Impact of Preferred Development Plan on Consumer Rates", which demonstrated the projected monthly electricity bills with and without the Ontario Sale. Using the data from this exhibit, the rate impact of the Preferred Development Plan on residential, small commercial and large industrial consumers is shown on the following figures.

Ms. Wray explained the figure entitled, "Projected Residential Bills", as follows:

> "This graph shows the impact of Manitoba Hydro's Preferred Development Plan on the monthly bill of a typical Winnipeg residential customer using 1,000 kilowatt-hours a month. The billings are expressed in 1990 dollars; that is, they have been justified to remove the effects of inflation estimated at 5 percent per year.
>
> Currently, this consumer is paying $51 a month. In both the sale and no-sale cases, real, that is, inflation-adjusted bills, are expected to decline over the next 30 odd years, but the decline will be steeper and rates even lower if the Ontario Hydro sale proceeds. Monthly bills are expected to begin diverging in the year 1996, before the Ontario Hydro sale even begins. By the year 2000, there will be a 4 percent difference in rates between the two cases, increasing to 8% or about $3 a month in today's dollars by 2010, and 15% by the end of 2027.

> The actual numbers shown in this graph assume that the bills of residential and other customer classifications will increase in proportion to long-term projected average annual rate increases. Class rate restructuring could affect the actual numbers, but not the relative difference in monthly bills between the sale and no-sale cases."

(Transcript, Volume 2, pages 243-244):

Ms. Wray summarized the figure entitled, "Projected Small Commercial Bills", as follows:

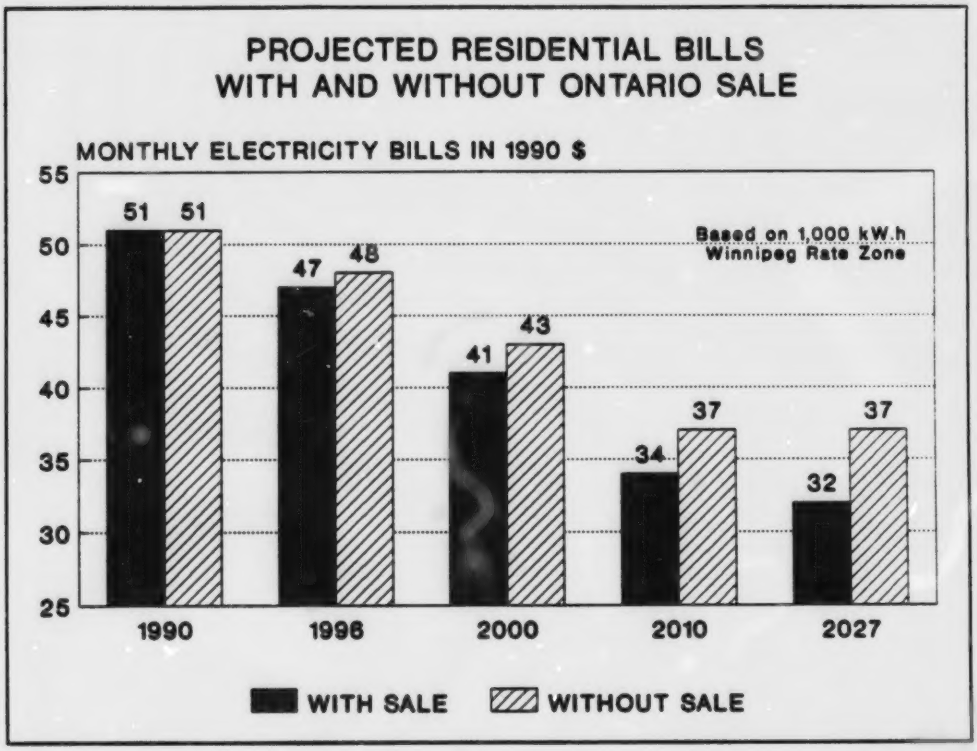
> "These bill projections refer to a small commercial customer under Manitoba Hydro's general service small non-demand rate schedule. Typical customers at the 10,000 kilowatt-hours per month level might be convenience stores or larger farms on the general service tariff. Their current monthly bill is about $500.
>
> "These customers would experience an overall decline in the real price of electricity similar to those shown for the residential class. A further percentage reduction on bills resulting from the Ontario Hydro sale is also the same. The dollar amounts for the sale reduction are, of course, larger, starting with a $4 per month reduction in 1996, and reaching $50 a month in today's dollars by 2027."

(Transcript, Volume 2, pages 244-245)

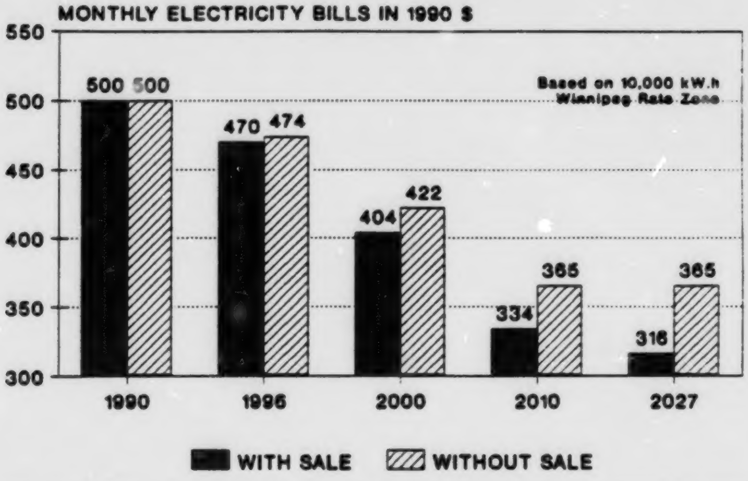
Ms. Wray explained the figure entitled, "Projected Large Industrial Bills", as follows:

> "Large industrial customers would also see similar bill reductions. A customer with a demand of 1,000 kilowatts and monthly consumption of 400,000 kilowatt-hours is currently paying $15,000 a month. Again, in real terms, Manitoba industrial power rates are expected to decline over time as they will for all other consumers. As with other ratepayers, the Ontario sale would enhance this benefit by a further 1 percent in 1996, by 4 percent in 2000, and so on, accumulating to 15 percent by the end of 2027. In dollar terms, adjusted for inflation, the Ontario sale is expected to result in savings of $1,000 a month to typical large industrial customers by the year 2010. The savings will continue to grow even beyond the period of financial analysis which ends in 2027."

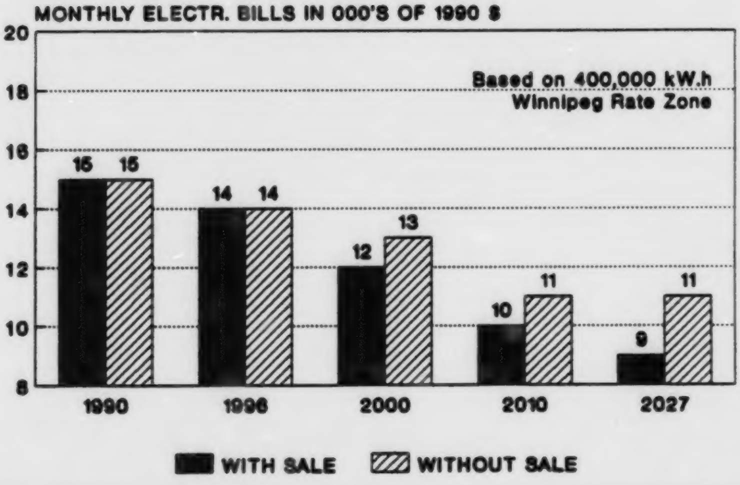
(Transcript, Volume 2, pages 245-246)



PROJECTED SMALL COMMERCIAL BILLS WITH AND WITHOUT ONTARIO SALE



PROJECTED LARGE INDUSTRIAL BILLS WITH AND WITHOUT ONTARIO SALE



Risk

Manitoba Hydro emphasizes that its rate scenarios are provided for comparative purposes only. The forecasts on which they are based, while they were prepared on a consistent basis, are subject to uncertainty in almost every component. Changes in projected load growth, market conditions, interest, exchange, escalation rates and numerous other factors could all significantly affect the levels of rate increases forecasted.

The last section of this report entitled, "Risk Assessment", will summarize the effect that changes in some of these variables would have on rates projected in the base forecast.

Borrowing Requirements

Borrowing requirements, although not a major issue in the past, are now another factor to be considered within the context of the Province's total borrowing capacity.

The Province of Manitoba's estimated Canadian dollar market availability and borrowing requirements over the period 1990 to 2010 are shown on the following page. This estimate assumes a 5% annual escalation of the market availability from the base year and that the provincial credit rating will remain in the A grade levels or above. The graph indicates that Manitoba's ability to borrow exceeds its borrowing requirements during this period.

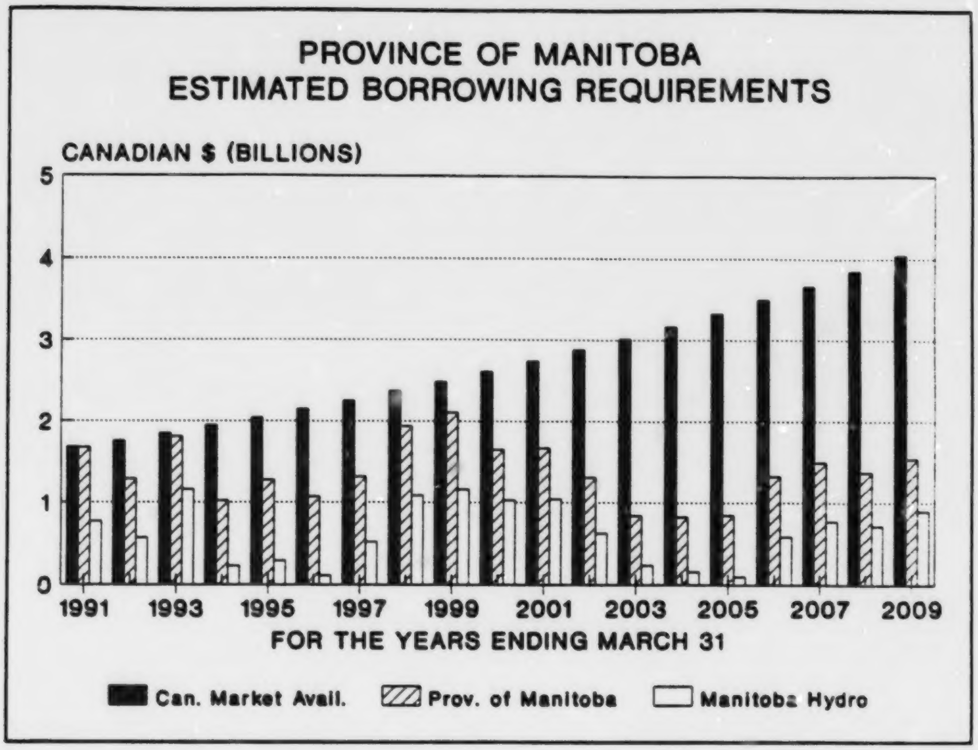
In addition, there is also a significant market availability in U.S. dollars to meet Manitoba Hydro's borrowing requirements. Since this U.S. dollar market availability is not included, the graph depicts a very conservative estimate of market availability.

During the public hearing, Manitoba Hydro filed Exhibit #MH-16 in response to a Board member's question regarding borrowing requirements.

It stated the following:

> "Total Canadian Market Availability of Funds was derived from informal discussions with Manitoba's Underwriters. It was confirmed that Manitoba's bond rating is in no way expected to be adversely affected by the proposed program. It should also be noted that Manitoba's Deputy Minister of Finance is a member of the Electrical Energy Marketing Committee and Manitoba Hydro's Board of Directors, is Executive Director of the Manitoba Energy Authority and was party to all decisions regarding the financing of Manitoba Hydro's proposed development plan."

Manitoba Hydro concludes that an adequate supply of funds will be available to meet Manitoba Hydro's Preferred Development Plan and there will be no difficulty in raising the necessary funds at competitive interest rates. The following figure also suggests that Manitoba Hydro's capital borrowing requirements would have to more than double in the late 1990's before the Province's Canadian borrowing capacity was exhausted.



Financial Forecast Assumptions and Methodology

Each scenario was analyzed in accordance with the objectives described in the previous section entitled: "Financial Targets and Rates Strategy". Two sets of financial forecasts were prepared for each scenario:

1) With priority given to adherence to the long-term 85:15 debt/equity target.

2) With priority given to limiting rate increases to the rate of inflation.

Because of the emphasis placed by Manitoba Hydro and its customers on the importance of rate stability, the alternative capital plans are ranked on the basis of Method 2. However, Method 1 is informative in showing how capital expenditures and export revenues affect financial results prior to rate smoothing.

Because of timing, none of the forecasts includes the effect of adjusting the proposed 4.5% 1990/91 rate increase to 4% as required by PUB Order 43/90. For simplicity and comparability, Manitoba Hydro assumed a uniform rate increase scenario of 4.5% per year from 1990/91 to 1994/95 for each scenario. Only the Preferred Development Plan

(Scenario 1) is adjusted to incorporate the outcome of the 1990 Rates hearing and the associated effects on the short-term rate scenario.

Individual Scenario Analysis

Plant additions and export sales are the major factors affecting financial results and rates for the scenarios examined. In accordance with generally accepted accounting principles, Manitoba Hydro capitalizes the costs of plant under construction and related financing charges until in-service date. As generation and transmission units come into service, a proportionate share of depreciation and finance expense is charged to operations.

Export revenues help to offset the sharp increase in financial expenses arising when new facilities come into service. Because it takes a number of years for domestic load growth to catch up to new installed capacity, surplus quantities of power are sold on the export market. Firm contracts with other utilities such as Ontario Hydro command a higher price than spot sales. In either case, they afford an opportunity to lessen rate increases to Manitoba consumers.

Position of Independent Witnesses and Intervenors

A. Economic Evaluation

GWC

On page 15 of his pre-filed testimony, GWC concluded that the revenues from the Ontario Sale compensated for the high capital costs of the Preferred Development Plan, but this conclusion was qualified as follows:

> "The economic comparisons . . . clearly indicate that the revenues to be derived from the Ontario Hydro sale more than compensate for the high capital cost of the preferred sequence of development. These revenues overshadow by a considerable margin any savings in first cost achievable with some other lower cost sequences.
>
> However, it must be recognized and emphasized that these evaluations are being made in respect of costs that will be incurred over the next decade to the year 2000 and revenues that will be accrued for twenty years thereafter. There is nothing in the agreement that would allow relief in the event that some grossly unfair situation were to develop during the intervening thirty years."

GWC's concerns regarding the unforeseeable future are dealt with in the following section entitled, "Risk Assessment".

CAC/MSOS

On page 46 of its closing arguments, CAC/MSOS recommended the use of a 15% interest rate as a more appropriate hurdle rate:

> "Manitoba Hydro used a 10% hurdle rate for contract negotiations. This consists of a 5.25% (now 5.50%) cost of capital as break even, and the

> remaining 4.75% (now 4.50%) which is the risk premium. Colloquially, we can refer to it as a cushion or a profit. Is 4.50% an adequate risk premium, or, putting it another way, is 10% an adequate hurdle rate? In light of the risks . . . and normal private sector expectations, we believe that it is at best marginal. A hurdle rate of 15% would be more appropriate."

Manitoba Hydro's response to this recommendation (and to CSC's similar recommendation below) was as follows (from page 36 of its Rebuttal Evidence):

> "It should be recognized that a risk premium is usually only added to the normal discount rate as a substitute for a more detailed analysis of the risk inherent in the base cashflow projections. Instead of using a hurdle rate to assess the attractiveness of export transactions, Manitoba Hydro applies other measures such as a present value revenue/cost ratio. In addition, sensitivity analysis is undertaken of such key variables as capital costs, load growth, general inflation, interest, etc., leading to the conclusion that the Preferred Development Plan maintains its preferred status under a variety of conditions, including a nominal discount rate significantly higher than 13.5%."

During the public hearing, CAC/MSOS acknowledged that it is not appropriate to combine the hurdle rate approach and the sensitivity analysis approach to risk assessment (Transcript, Volume 10, page 2257). Since the purpose of a higher discount rate would be to provide a cushion for uncertainties, it should only be applied to the base case scenario as opposed to a scenario that reflects something other than the most likely scenario.

The Board's review of Manitoba Hydro's sensitivity analyses is discussed in the next section entitled, "Risk Assessment".

CSC

CSC evaluated the Preferred Development Plan using an implicit comparison with a scenario based on 5 times DSM, thermal life extension, renewal of diversity agreements, re-runnering of Kettle Generating Station, basing system energy capability on 15 percentile flows rather than low flows, and purchase of 100 MW or use of gas turbines in order to delay construction of the next major hydro plant to the year 2022. Results of the comparison were presented in Exhibit CSC-7 which showed that the Manitoba Hydro Preferred Development Plan was not profitable and in fact was more costly by a margin of $351 million (1989 present value dollars).

Manitoba Hydro's response was that the CSC evaluation had omitted benefits of the Manitoba Hydro Preferred Development Plan, totalling $341 million, as detailed in Exhibit #MH-34. CSC admitted to omissions totalling $73 million.

Manitoba Hydro further submitted that CSC had used inflated social discount rates to reflect assumed societal costs of the Manitoba Hydro Preferred Development Plan while omitting to add societal benefits.

MIPUG

On pages 12-14 of its closing argument, MIPUG notes that the Ontario Sale represents a least cost option at real discount rates well in excess of any reasonable estimate of Manitoba Hydro's costs for borrowing:

> ". . . the Ontario Sale represents a least cost option at real discount rates well in excess of any reasonable estimate of Manitoba Hydro's costs for borrowing, e.g. 5.5 per cent (net of inflation and including debt guarantee fees), as well as in excess of real discount rates adopted by other Canadian Crown utilities to assess similar options (e.g., an approximate 8.0 per cent real discount rate has applied for such purposes in B.C. or Quebec); in fact, the analysis indicates that positive net benefits have been obtained at real discount rates as high as 10.0 per cent under a very wide range of sensitivities with and without thermal life extension, with and without diversity agreement extension (both without and in combination with the thermal life extension option), with and without extensive increases in DSM (including increases in DSM targets to five times present levels, and including a case with DSM achieving ten times present targets by the year 2020.
>
> MIPUG concurs with the criteria and methodology adopted by Manitoba Hydro for the purposes of its customer-oriented economic analysis of least cost options and related sensitivity tests. We see no reasonable basis in this regard for suggesting a criterion that the Ontario Sale (or any other development option) must achieve net benefits related to the next best available option measured at any suggested real discount rate in excess of Manitoba Hydro's expected real cost for borrowing. We also see no basis for suggesting that any arbitrary "adders" be incorporated in Manitoba Hydro's economic sequence analysis to reflect presumptions about net impacts (positive or negative) relating to societal environmental or socio-economic impacts external to Manitoba Hydro costs relevant to domestic customer rates. (We note that the available evidence in any event confirms that the broader Manitoba society would receive significant net benefits from the Ontario Sale, even after consideration of somewhat higher opportunity costs for capital than those appropriate for Manitoba Hydro's economic analysis. We believe that the evidence also indicates "global" net benefits if the overall North American society is considered.)"

The Board notes that MIPUG concurs with Manitoba Hydro's sequence evaluation criteria and methodology.

NFC

NFC concluded on page 12 of its closing argument that the decision whether to use higher discount rates was not relevant to the decision as to the next generation plant:

> "The Public Utilities Board has had the opportunity of hearing considerable evidence with regards to discount rates. The NFC, on reflecting on that evidence, is of the view that the decision before the Board is a public policy decision involving a choice between alternative courses of action, rather than a commercial basis. The Manitoba Hydro Board has set a hurdle discount rate of 10% real, and Manitoba Hydro Exhibit

> No. 40 (Figures A1 and A2) demonstrates that for all realistic scenarios the Board's test is met. The Manitoba Hydro Board's test, in the view of the NFC is reasonable. In fact, as a commercial decision, a higher discount rate would no doubt be required. That higher discount rate appears not be be relevant to the Public Utilities Board decision . . ."

B. Socio-Economic Evaluation

GWC

On page 15 of his pre-filed testimony, GWC concluded that the socio-economic analyses further support Manitoba Hydro's choice of scenario.

As previously noted above, Manitoba Hydro has stated that it had not put much weight on the results on its socio-economic evaluation in selecting its Preferred Development Plan.

CAC/MSOS

CAC/MSOS had the following comments regarding the socio-economic benefits of Manitoba Hydro's Preferred Development Plan (page 53 of its closing argument):

> ". . . the socio-economic benefits of Manitoba Hydro's preferred development plan are primarily due to a timing difference. In effect, what Manitobans are doing by building Conawapa and Bipole III sooner rather than later is stimulating the economy now rather than stimulating it later. In employment terms, what we are doing is taking away jobs away from our children, ten to twenty years from now, in order to give those jobs to ourselves today. No more jobs are created one way or another. No more stimulation is provided one way or the other. The simple difference is one of timing."

As previously noted above, the results of Manitoba Hydro's socio-economic evaluation is outside the Board's terms of reference as provided by Order in Council No. 177/90.

CSC

On page 47 of its closing argument, CSC raises the issue as to what discount rate should have been used in Manitoba Hydro's socio-economic evaluation:

> ". . . Manitoba Hydro states "it is inconsistent to use an 8% real discount rate to measure societal impact without also adding back the benefits of water rentals, tax revenues and reduced unemployment to the province. This approach assumes that only the hydro-electric and other projects contained in Manitoba Hydro scenarios create tax revenue and reduce unemployment to the province. Any scenario that had as a component a significant demand-side management program also create tax revenue and reduce unemployment to the province. As it happens, DSM would employ more people per dollar spent than hydro-electric construction. Manitoba Hydro has only attempted to analyze the employment and related benefits that accrue from its preferred development plan. Goodman and Marcus, on the other hand, took into account the offsetting effect that demand-side management and

> other components of their "proximation of a least cost plan" would have on employment and related matters. Consequently, CSC submits that there is no basis for altering the 8% real discount rate as a result of employment factors."

Manitoba Hydro responded to this concern on page 53 of its closing argument as follows:

> "Goodman and Marcus advocated an 8% real discount rate to measure costs to society, but made no adjustments to Manitoba Hydro's private revenues and costs before applying this rate.
>
> (Transcript, Volume 17, pages 3747-3750)
>
> Manitoba Hydro submits that it is inconsistent to use an 8% real discount rate to measure societal impacts without also adding back the benefits of water rentals, tax revenue and reduced unemployment to the Province."

MIPUG

On page 6 of its closing argument, MIPUG agreed with CAC/MSOS that the socio-economic impacts related to the Ontario Sale are primarily due to timing differences:

> "Environmental and socio-economic impacts related to the capital facilities required for the Ontario Sale (e.g., Conawapa and Bipole III) are affected by the Ontario Sale only to the extent that such impacts are accelerated.
>
> The Board has sufficient evidence to determine that environmental and socio-economic risks and potential concerns related to Conawapa and Bipole III will not affect the viability of these projects as least cost options to meet Manitoba's needs in the context of an Ontario Hydro sale."

The Board notes that MIPUG's views concur with those of CAC/MSOS and Manitoba Hydro and with those of NFC as stated below.

NFC

NFC agreed that the decision as to the next generating plant would not be decided by the results of Manitoba Hydro's socio-economic evaluation:

> "Several witnesses provided expert opinion with respect to the social cost benefit analysis of the project. While all of those witnesses (Dr. Shaffer, Dr. Brown and Dr. Fenton) were critical of the incomplete nature of the environmental impact assessment process, it would appear that the determination of whether the proposed scenario is recommended by the Public Utilities Board will not turn on the social cost benefit analysis."
>
> (NFC, Written Argument, page 11)

C. Environmental Evaluation

CSC

CSC noted that until an environmental assessment is completed, it cannot conclude as to the environmental impacts of Manitoba Hydro's proposed capital projects:

> "Manitoba Hydro has not completed its own environmental assessment. It has not begun either federal or provincial environmental assessment processes. Manitoba Hydro admits that its review of environmental impacts is incomplete. In the circumstances, little can be concluded with respect to the environmental impacts."

Manitoba Hydro responded that its evaluations adequately and properly reflect any environmental impacts of its proposed projects (page 53 of its closing argument).

NFC

On pages 14-15 of its closing argument, NFC recommends that an additional allowance should be made for mitigation and compensation costs:

> "The NFC notes with alarm the evidently low estimates of the costs of mitigating and compensating for environmental damage arising from construction and operation of Conawapa and Bipole III. These estimates have been prepared without reference to, and prior to undertaking full environmental impact assessment as specified by Provincial and Federal Law.
>
> While appreciating that ultimately the overall recommendation of the Public Utilities Board will not depend upon the "numbers" used for cost of mitigation and compensation for environmental impact, the NFC recommends to the Board that an additional allowance should be made for the cost of mitigation and compensation."

Manitoba Hydro responded to these concerns in its closing argument:

> "Several intervenors . . . have argued that there may be potential or hidden environmental costs that have not been considered, which could be of sufficient magnitude to affect the viability of the project.
>
> Manitoba Hydro suggests that there are in effect two types of environmental costs. The first consists of all those costs which flow through Manitoba Hydro's accounts and which must eventually be passed on to its customers. This includes all of the costs associated with conducting environmental impact studies, environmental assessments, public hearings and participation, etc. It also includes the construction and operating costs of structures and facilities required to prevent or mitigate environmental damages, and the expenses of activities (such as special employment initiatives) undertaken to minimize any

> negative and maximize any positive socio-economic impacts of the projects. It also includes any compensation, in cash or in kind, that must be made to individuals, groups or communities adversely affected by the projects.
>
> (Transcript, Volume 19, pages 4323-4326)
>
> Allowances for all these types of costs are included or internalized in the project estimates. Manitoba Hydro has also testified that it has performed sufficient environmental studies to date, that, coupled with its recent experience on comparable projects, it can be confident that it has not overlooked any significant potential environmental impact associated with any of the proposed projects which would have a material effect on the cost of that project.
>
> (Transcript, Volume 19, pages 4314-4321)
>
> The second type of environmental costs are sometimes referred to as externalities, but would be better described as residual environmental impacts for which it is virtually impossible to reach consensus on value. One cannot identify a directly impacted party, and there is no one to receive payment for this impact. These tend to be aesthetic or quality-of-life type impacts that affect society at large and there are no costs to be reflected in hydro customer bills.
>
> Manitoba Hydro submits that the most appropriate way to incorporate environmental costs and concerns into the selection among schemes is to "internalize" all appropriate costs, and then apply the qualitative critical value approach (i.e., the socio-economic evaluation) to assess the externalities."
>
> (Manitoba Hydro, Written Argument, pages 53-56)

D. Financial Evaluation

With regard to Manitoba Hydro's financial evaluation, CAC/MSOS had two conclusions:

> "The financial risks associated with future major exports of firm power should be borne by private investors, not Manitoba Hydro customers."
>
> (CAC/MSOS, Written Argument, page i)

This will be dealt with under the "Risk Assessment" section.

The second conclusion related to CAC/MSOS' views that the distribution of profits through Manitoba Hydro's rate structure was inappropriate as it sends the wrong price signal to consumers creating overconsumption and the need for additional generating stations and transmission lines. It was argued that such a practice was inconsistent with Manitoba Hydro's mandate as well as the principle of sustainable development. CAC/MSOS argued that:

> "Instead, if every customer in Manitoba were given an annual "dividend" cheque or an equivalent credit by Manitoba Hydro that is not directly related to consumption, that would avoid the export profits having the effect of reducing the price of electricity in Manitoba."

(CAC/MSOS, Written Argument, page 64)

Manitoba Hydro responded to CAC/MSOS' recommendations in its closing argument:

> "Manitoba Hydro's position is that any excess revenues over costs resulting from any of the initiatives in the Preferred Development Plan would be used to lower rates. This approach is consistent with government policy, as reflected in the recent repeal of Manitoba Energy Foundation Act.
>
> (Transcript, Volume 6, pages 1320 and 1322)
>
> The manner in which revenue requirements should be distributed among different customer classes is handled through the annual Cost of Service Study which is examined at Public Utilities Board rates hearings (Transcript, Volume 6, page 1323)."

(Manitoba Hydro, Written Argument, pages 86-87)

MIPUG

In its closing argument, MIPUG summarized Manitoba Hydro's financial evaluation and noted that other intervenors accepted Manitoba Hydro's methodology (pages 6-7):

> "MIPUG agrees with Manitoba Hydro that the distinction between financial and economic evaluations contributed to some confusion during the hearings; however, subject to specific disagreements with respect to the utilization of "profits" from the Ontario Sale, expert witnesses accepted Manitoba Hydro's methodology for financial evaluations of the relevant sequence options. MIPUG submits that matters pertaining to long term financial objectives, financial targets and the determination of rates should be examined in this hearing only to the extent required to assess the proposed Ontario Hydro sale. The evidence establishes that approval of this sale is not in any way contingent upon the assumption that future rates must be established in accordance with Manitoba Hydro's present long term debt/equity targets, and that alternative debt/equity targets would not affect the validity or assessment of the Ontario sale."

The Board notes that none of the independent witnesses or intervenors disagreed with Manitoba Hydro's financial evaluation.

The Manitoba Chamber of Commerce

The Manitoba Chamber of Commerce (the "Chamber") appeared as a presenter during the public hearing. One of the Chamber's main concerns dealt with Manitoba Hydro's debt:equity ratio. The Chamber pointed out that the debt:equity ratio changed from 96:4 (rounded) in 1979 to 98:2 in 1989 and noted that the debt:equity ratio was not improving.

The Chamber took some comfort from Manitoba Hydro's intent to move to a 91:9 debt:equity ratio by 1995, and to reach a debt:equity ratio of 85:15 by 1997 with further improvements beyond that.

(Transcript, Volume 1, pages 108-110)

Board Findings

The Board has reviewed Manitoba Hydro's economic, socio-economic, environmental and financial evaluations and has considered all the views of the independent witnesses and intervenors.

Economic Evaluation

Regarding the economic evaluation, the Board notes that the net benefit of its Preferred Development Plan versus Scenario 2 is $696 million in 1989 present value dollars. In response to intervenors' concerns that the benefits of the Preferred Development Plan were being supplemented by the economic benefits provided by the three other initiatives of the Preferred Development Plan, the Board performed its own calculation of the direct benefit of the Ontario Sale. The final results of this calculation demonstrated that the direct benefit of the Ontario Sale is $468 million in 1989 present value dollars.

The Board concludes that the Ontario Sale and its related System Participation Agreement and Facilities Agreement is economically sound, subject to an analysis of the risks associated with the economic benefits (which will be analyzed in the last section entitled, "Risk Assessment").

After careful consideration of the testimony, exhibits and source calculations relating to CSC-7, the Board finds that the calculations omitted benefits of the Preferred Development Plan totalling $341 million as claimed by Manitoba Hydro; that the discount rate used was inappropriate for an economic analysis, resulting in a $433 million overstatement of cost, and that no testimony before the Board would justify imposing a $127 million greater assumed environmental cost on the Manitoba Hydro Preferred Development Plan than on any other scenario.

The Board further finds that the Manitoba Hydro Preferred Development Plan involves lesser costs than the scenario envisaged by CSC.

In regard to CAC/MSOS' view that any benefits from the Preferred Development Plan should not be distributed through the rate structure but rather through for example, a "dividend cheque to all Manitobans the Board disagrees for the following reasons:

1) It is unfair for the ratepayers of Manitoba Hydro to take responsibility for all the costs of Manitoba Hydro through the rate structure and yet, through the rate structure not share the benefits.

2) The Board's view on this matter is consistent with concerns it expressed in its previous Manitoba Hydro rate decisions.

3) The position advanced by CAC/MSOS was essentially part of The Manitoba Energy Foundation Act which was repealed in March, 1990.

Socio-Economic Evaluation

Regarding Manitoba Hydro's socio-economic evaluation, the Board agrees with MIPUG, NFC and Manitoba Hydro that the decision as to the next generating station does not turn on the results of that evaluation. The Board repeats its earlier statement that the socio-economic evaluation is outside its terms of reference as provided by Order in Council No. 177/90.

Environmental Evaluation

The Board is limited in its evaluation and possible findings of the Preferred Development Plan and Scenario 2 by Section 1 (d)(iv) of Order in Council No. 177/90 which states in part:

> "By reason of the fact that these same capital projects will be the subject of hearings before the Clean Environment Commission, analyses of risks should include possible modifications to the capital projects resulting from the environmental review."

The Board is of the view that its conclusions as to the environmental evaluation should be limited to estimating, to the degree possible, whether Manitoba Hydro environmental cost estimates for the Preferred Development Plan and Scenario 2 are adequate.

The Board is not qualified to conclude as to the existence and magnitude of any unquantified environmental costs. The Board does note that Manitoba Hydro's estimate of the net benefit of its Preferred Development Plan would be reduced should there be any environmental costs over and above those already included in its capital cost estimates. The risk of such an occurrence is dealt with in the following section entitled, "Risk Assessment". In that section, the results of Manitoba Hydro's sensitivity analyses indicate that should capital costs (which would include additional environmental costs) increase by 10%, the $696 million net benefit of the Preferred Development Plan would decrease by $92 million to $604 million in 1989 present value dollars.

On the basis of the overview studies and impact assessment work done to date (Transcript, Volume 19, pages 4314-4321), Manitoba Hydro has stated that it has no reason to believe that any unquantified costs in excess of the amounts already included in its capital cost estimates, are anywhere near the estimated net benefits of its Preferred Development Plan.

The Board is satisfied that the $696 million net benefits of the Preferred Development Plan provides a cushion for substantial unquantified environmental costs.

The Board also notes that the environmental impacts of Conawapa (under the Preferred Development Plan) versus Wuskwatim (under Scenario 2) are less severe in terms of flooding. Under the Preferred Development Plan, Conawapa would result in 4 square kilometers of flooding along the Nelson River whereas under Scenario 2, Wuskwatim would result in 127 square kilometers of flooding along the Burntwood River.

NFC concluded in its closing argument (page 11) that it "opposes in principle the construction of any dams on the Nelson River, other than Conawapa, and any dams on the Burntwood River, including specifically Wuskwatim, until broad study is completed on the impact of hydro-electric development on northern ecosystems and aboriginal communities...." The Board concludes from NFC's statement that it is likely that it would be more difficult to get environmental approval from the Clean Environment Commission for Scenario 2 versus Manitoba Hydro's Preferred Development Plan.

Financial Evaluation

Regarding the financial evaluation, Manitoba Hydro has determined that Manitoba customers will save $441 million in 1989 present value dollars under the Preferred Development Plan as compared to Scenario 2. Whereas the $696 million net benefit of the Preferred Development Plan represents the net cost difference between the Preferred Development Plan and Scenario 2, the $441 million represents the difference in the present value of the revenues generated from these two scenarios from 1996 to 2027.

As previously stated, this $441 million savings is expressed in 1989 present value dollars and is equivalent to $5.1 billion in current dollars over the period 1996 to 2027. In other words, if the Preferred Development Plan is rejected and Manitoba Hydro proceeds with Scenario 2, Manitoba Hydro would have to collect an additional $5.1 billion from consumers over the period 1996 to 2027.

The Board concludes that the Preferred Development Plan is the least cost alternative, in economic and financial terms, when compared to Scenario 2, subject to the assessment of related risks which is presented in the next and last section.

Risk Assessment

Sources of Risk

Manitoba Hydro's position on risk is as follows:

> "Manitoba Hydro is intrinsically risk-averse. That is, it will only cautiously undertake any activity where it has a low degree of confidence as to the outcome.
>
> The assessment, evaluation and management of risk applicable to all options is inherent in every decision or activity the Corporation takes."
>
> (Manitoba Hydro, Exhibit #MH-3A: Risk Management and Exposures, page 3)

Manitoba Hydro's Submission indicated that there are two categories of risk to which the Corporation is exposed in its Preferred Development Plan.

1) The underlying or assumed economic and financial conditions may change.

This category of risk is beyond Manitoba Hydro's control, but to determine the Preferred Development Plan's viability, it is evaluated against a wide range of possible variations in economic and financial factors. These 'sensitivity' tests examine ranges such as plus or minus 30% accuracy in capital cost estimates, plus or minus 10% variation in load, interest rates up to 18%, and so on.

Manitoba Hydro concludes that both the economic and financial benefits of components of the Preferred Development Plan have been found to be robust under plausible combinations of variables. In particular, the Ontario Hydro sale and the diversity exchanges provide a degree of certainty and protection that would be absent without them.

2) Work on the agreements and plant cannot or does not proceed as planned.

Evaluation of the possible impacts of the second category of risk is much more complex. In effect, there is an infinite number of permutations and combinations of possibilities that could impede progress, ranging from one of the parties cancelling a contract at an early stage, to a disastrous fire at Conawapa or Riel. During the public hearing Mr. Adams added the following comments regarding extraordinary events:

> "Events that might have a significant impact on Manitoba Hydro include such things as a major war involving Canada and the U.S., sudden impositions of taxes or restrictions on the production of carbon dioxide, a serious accident at a North American nuclear generating station, political instability within Canada, and so on.

> In the vast majority of such instances, the value of having additional hydro-electric capacity in Manitoba is judged to be enhanced, lending directional support to the Preferred Development Plan.
>
> The exact impact of any such event would depend upon its nature, its timing, water conditions in the reservoirs at the time, what could be done to recoup or recover, what arrangements could be made with other utilities, and so on. Any analysis at this stage can only be speculative."

(Transcript, Volume 3, pages 518-519)

Manitoba Hydro makes certain general observations regarding risk. For the most part, risks are managed by anticipating and avoiding them. For example, extensive subsurface investigations are performed at construction sites to minimize the possibility that foundation conditions could later cause problems. Extensive security and fire protection procedures are employed. Collective Agreements are arranged for workers at the site to prevent labour difficulties. Extensive inspection and expediting procedures are performed to prevent supplier delay or default. Manitoba Hydro endeavours to anticipate and comply with the requirements of the environmental review and licensing process. It allows adequate time for property expropriation should negotiations fail. In fact, these are the normal risks of doing business, and much of the Corporation's day-to-day activities are aimed at reducing the likelihood or the impact of all the risks it can reasonably foresee.

Risks that cannot be managed by Manitoba Hydro include the traditional areas of war, civil strife, and economic collapse. One of the greatest uncertainties at this time is the risk associated with the emerging process of obtaining environmental licenses. Until the question of Federal and/or Provincial jurisdiction is clarified, as well as a legally enforceable process firmly established, there remains a chance that the appropriate approvals cannot be secured or may be delayed.

During the public hearing, Manitoba Hydro filed Exhibit #MH-3A entitled, "Risk Management and Exposures", which addressed in considerable detail Manitoba Hydro's vulnerability to various contingencies and the mitigating measures used to protect against those risks. In that document, Manitoba Hydro stated the following:

> "In negotiating any agreement, the risks and rewards inherent in that agreement must be assessed and apportioned. This is a dynamic process, which usually results in neither party achieving everything it might want. However, Manitoba Hydro would not agree to anything that did not meet its minimum requirements for protection against certain specified risks. Negotiations with Ontario Hydro were conducted by Manitoba Hydro staff experienced in developing inter-utility agreements and in negotiations. Progress, potential opportunities and potential risks were regularly reviewed by expert staff throughout the Corporation, and presented to the Board of Directors on a regular basis."

(Exhibit #MH-3A, page 16)

The attached table summarizes the risks, potential adverse consequences and mitigating measures set out on page 18 of Exhibit #MH-3A.

Ontario Hydro 1,000 MW Firm Power Sale
Risk Exposure and Protection

(Source: Exhibit #MH-3A, page 18)

	Contingency	**Potential Adverse Consequences**	**Mitigating Measures**
1.	Domestic load growth, effective discount rates, surplus energy rates higher or lower than predicted.	Agreement could become uneconomic.	Set price high enough to provide good benefit/cost ratio under all reasonable circumstances. Sensitivity study.
2.	Interest rates increase.	Capital cost and interest payments increase.	Demand payments based on Manitoba Hydro actual cost of capital.
3.	Inflation rates increase.	Capital and future operating costs higher.	Demand payments based on Stats. Canada Construction Index. Energy payments based on CPI.
4.	Energy values increase significantly.	Revenues less than alternative markets.	Approximately 50% of revenue escalates with CPI, Ontario line provides alternative to NSP.
5.	Force Majeure in Manitoba.	Difficulty in supplying for extended period, loss of revenue.	Sale is a system sale, and part of planned load.
6.	Force Majeure in Ontario.	Difficulty in Ontario receiving for extended period.	Take or Pay provision.
7.	Transmission system problems in Manitoba.	Unable to meet 95% monthly availability factor.	Revenue loss specified. Incentive to perform.
8.	Transmission system problems in Ontario.	Ontario unable to receive.	Take or Pay provision.

9.	Drought in Manitoba.	Unable to meet all commitments.	Manitoba load gets preference. Energy deferral provision.
10.	Approvals not granted.	Agreement must be cancelled after costs incurred.	Cancellation period provided. Penalties defined. Exposure limited.
11.	Opportunities for future sales cost.	Possibly a better deal would become available.	Discussed extensively with NSP, NPPD, Wisconsin, UMPG, Montana, etc.
12.	Inflation is negative after 2000.	Reduced revenue.	Approximately 50% revenue fixed Manitoba Hydro Operating Costs reduced.
13.	Early increase in interest, depreciation and operating expenses.	Manitoba customers required to pay more initially to gain later benefits.	"F" factor introduced to move revenue to earlier years.
14.	Capital cost overruns in Manitoba.	Increased investment and Manitoba rates.	Common to scenario with or without Participation System Agreement. Sensitivity study up to +30%.
15.	Capital cost overruns in Ontario (1,000 km, $1 Billion+).	None.	-
16.	New plant unavailable in Manitoba.	Difficulty in supplying load.	Manitoba load gets preference. Supply not tied to specific plant (System sale).
17.	Ontario Hydro transmission line not complete.	Unable to deliver power, loss of revenue.	Take or Pay provision.

Impacts of Risks

Manitoba Hydro's Submission states that regardless of the source of a risk or the cause of an event, the impacts would generally affect Manitoba Hydro's Preferred Development Plan in one of the following three ways:

1) The export or diversity agreements would have to be cancelled because of the failure of one or both of the parties to obtain the necessary approvals. (#10 of Risk Protection and Exposures table on page 4)

   The impacts would be mainly financial, although if the diversity exchange were cancelled, there could be difficulties in meeting demand in 1999 and 2000. Generally, the cancelling party would be required to compensate the other either in accordance with the terms of the contract or as determined by litigation. The extent of the damages would depend upon the timing of the cancellation. For example, the possibility of not receiving approval was recognized at the time of negotiation, so the Ontario agreement includes time-related provisions which could end the contract and define the cancellation payment. Obviously, in the event of cancellation, the anticipated benefits associated with the contract would be lost.

2) Delays in project approvals and/or construction schedules in Manitoba could jeopardize Manitoba Hydro's ability to meet its domestic and export commitments. Delays affecting extra-provincial utilities could jeopardize their ability to receive the power. (#5 - #8 and #10 of Risk Protection and Exposures table on pages 3-4)

   The impacts would be primarily financial, although adequacy of supply could be an issue. Short delays might be addressed by purchases, accommodation with Ontario Hydro, or by assuming an increased risk of supply shortage. Longer delays may require installation of gas turbines, increased purchases of power, appealing for reduced consumption by all customers, or negotiating load reductions with major Manitoba consumers. The result of delays which could not be made up by extraordinary means would cause default on contractual obligations with exposure to litigated settlement. If curtailment of contractual obligations will not permit service to be maintained, the result may be reduction in service to Manitoba consumers. The cumulative costs of extraordinary measures and litigated costs have not been estimated.

   Construction delays would result in short-term shortages of up to 300 MW in 2000-2003. During the public hearing, Mr. Zaleski discussed the cost impact of a construction delay:

   > "The upper-bound cost impact would be around $70 million, 1989 present value, again still well within the benefits of the preferred development plan. In fact, the same cost should probably be applied to all scenarios, so that the net loss of benefits would be even less.
   >
   > If everything proceeds according to plan, except that construction-related problems were to occur near the end of the construction schedules, a

> possible outcome is that the in-service dates of one or more of the Conawapa units or a part of the Bipole III complex would be delayed.
>
> An upper-bound estimate of the cost of such a situation is gained by assuming that all of the Conawapa power is delayed by one year. In this case, there would likely not be adequate time to install combustion turbines and secure a reliable gas supply or other long-term measures. Consequently, short-term measures, such as retention of Brandon units 1 to 4, import capacity purchases, delay in deliveries to Ontario Hydro, and so on, would have to be pursued."

(Transcript, Volume 3, pages 532-533)

3) There may be increases or decreases in the costs of meeting all commitments. (#2, #3, #13 and #14 of Risk Protection and Exposures table on pages 3-4)

All cost estimates and economic and financial evaluations are based on assumed conditions, including reasonable construction schedules and stable economic conditions. Delays in approvals or construction might not be so severe as to delay completion, but might require acceleration of work (which usually involves additional costs). Similarly, escalation and interest rates might be higher, load growth might be lower, and demand management programs may cost more than anticipated or achieve lower results.

In practically all cases, these types of situations would not affect the Corporation's ability to meet its obligations, but they would have an impact on its financial position. The exact impact depends upon the extent and nature of the problem. The projected rate increases associated with the Preferred Development Plan are dependent on assumptions made with regard to inflation and interest rates, capital costs, load growth, interruptible export rates, water flows and a number of other variables.

The following table indicates the effect on rates of potentially adverse changes in some of these assumptions. The sensitivities selected were judged to have a reasonable probability of occurrence, though it is acknowledged that favourable changes in forecast variables could also occur. The effects of positive and negative variations are not necessarily symmetrical and could have more significant impacts than displayed in this table depending on the size and timing of the variation.

Preferred Development Plan - Risk Analysis
Rate Impact of Adverse Changes in Base Case Assumptions

	Year Ended	
Base Assumptions	**1996 - 2005**	**2006 - 2009**
Annual Rate Increases:	1.1%	5.0%
Sensitivities	**Average Annual Additional Rate Increase to 2009**	
General Escalation +1.5% per year	+0.90%	
Interest +1.5% per year	+0.75%	
Capital Costs +10.0%	+0.30%	
Drought 1996 and 1997	+1.40% from 1998 on	
Load Growth +100 MW by 2001	No rate impact to 2009 (higher thereafter)	
Interruptible Export Rates -20%	+0.37%	

During the public hearing Mr. Zaleski addressed the risk that domestic load growth becomes lower and/or demand-side management programs are more successful than anticipated, assuming that the preferred development plan proceeds:

> "If recognized soon enough and the need for the new generation is moved to beyond 2000, Conawapa and Bipole III could be delayed, with a net saving over current expectations. There could be domestic rate savings resulting from plant deferral, as well as upward rate pressures due to the distribution of the same revenue requirements over fewer kilowatt-hours.
>
> Low load growth was one of the sensitivities discussed . . . where the preferred development plan was confirmed to be economic. If the low load growth were not to be recognized prior to commencement of Bipole III and Conawapa, then the options would be to either complete them on schedule and market the surplus, or to delay completion until necessary as, for example, occurred with Limestone in 1978. The choice would depend on the circumstances at the time.
>
> The net cost to Manitoba consumers would only be nominal. Assuming completion as scheduled, the maximum penalty to Manitoba Hydro is equivalent to about $50 million, 1989 present value, for every year of early in-service. This figure would not be substantially different with any other development plan when low load growth was not recognized until late in the program."

(Transcript, Volume 3, pages 524-525)

Mr. Zaleski also addressed the risk that domestic load growth later becomes higher and/or demand-side management programs are less successful than anticipated, to the extent that in 1994, the demand in the year 2000 is forecast to be 240 megawatts higher:

> "If the problem was merely the ineffectiveness of the DSM program, and if this was recognized by 1995, the situation would be effectively that described in scenario 7, except that any expenditures on DSM would have to be reflected in revenue requirements at an earlier date. The major loss would be the $85 million, 1989 present value, that the DSM program is projected to provide.
>
> In this case, a 100-megawatt peak purchase would likely be negotiated for the year 2000, and that would be, if available, from neighbouring utilities; Brandon 1 to 4 retained beyond 2000; and Wuskwatim advanced to 2003. And again, regarding Brandon 1 to 4, the retention beyond 2000 would be regardless of what our perceived reliability of the plants would be. This would be sort of a fall-back position. These would entail no extraordinary cost impacts, and the preferred development plan would involve no penalty relative to any other development scenario.
>
> If the load growth were not recognized until after 1994, a 200-megawatt combustion turbine, together with a firm supply of natural gas, would likely be required for 2003, with an additional sequence cost of approximately $40 million, again in 1989 present value. Again, this cost would be substantially the same for any development scenario."

(Transcript, Volume 3, pages 526-527)

In preparing its Preferred Development Plan, Manitoba Hydro assumes that all parties will use their best efforts to meet their obligations, including securing the necessary licenses and approvals. It also accepts the necessity to ensure that all reasonable steps are taken to avoid or minimize the effects of undesirable or unexpected events.

During the public hearing, Manitoba Hydro filed Exhibit #MH-11 entitled, "Sensitivity Analysis of Ontario 1,000 MW Sale", which demonstrated the sensitivity of the economic evaluation of the Ontario Sale under certain assumptions. These sensitivities are summarized as follows:

Sensitivity Analysis of Ontario 1,000 MW Sale
In Millions of 1989 Present Value Dollars

Assumption		Ontario Sale Net Benefit
Best Estimates		696
Real Discount Rate:	Increased 1.5% (to 6.75%)	444
	Decreased 1.5% (to 3.75%)	1099
All Capital Costs:	Increased 10%	604
	Decreased 10%	791
Load Growth:	Up 240 MW	679
	Down 240 MW	652
Interruptible Export Rates:	Up 20%	726
	Down 20%	672
Altered DSM Program Size:	No DSM	669
	2 times	619
	5 times	630
Higher Real Discount Rates: (i.e. higher interest rates)	10%	82
	12%	-41
Interruptible Export Rates:	Increased 50%	765
	Decreased 50%	630
Diversity Exchange Extended Indefinitely		637
Thermal Life Extension LE-2		618

Note: "Benefit" reflects the difference in the present value of estimated costs of the Preferred Development Plan compared to the present value of estimated costs of scenario 2.

In response to a Board member's question during the public hearing, Manitoba Hydro filed Exhibit #MH-20 which set out the "Combined Impact of Adverse Sensitivities". This exhibit is summarized on the next page:

Manitoba Hydro
Combined Impact of Adverse Sensitivities
In Millions of 1989 Present Value Dollars
(Source: Exhibit #MH-20)

	Assumption	Ontario Sale Benefit
Best Estimates		696
Combined Sensitivity #1	Interest increased by 1.5% to 12% (i.e. real discount rate of 6.75%) Capital costs increased by 10% Interruptible export and import rates decreased by 20%	337
Combined Sensitivity #2	Interest increased by 1.5% to 12% Escalation increased by 1.5% to 6.5% (i.e. real discount rate of 5.25%) Capital costs increased by 10% Interruptible export and import rates decreased by 20%	581

Exhibit #MH-20 demonstrates the impact on the Ontario Sale benefit of the worst combination of adverse sensitivities. These economic evaluations still assume that water rentals escalate with inflation. The production costs used in the Table were obtained from a hydraulic simulation which models the entire range of historic water flows and therefore includes the impact of droughts and high flows. During the study period, including the Ontario Sale period, the impact of the most severe historic drought is included. The repetition of such a drought would not extend over the entire sale period, rather both low and high flows would likely occur. Therefore, the risks of drought are already incorporated in the production costs and in the economic analysis.

In the first combined risk scenario, the Ontario Sale benefit is reduced from $696 million to $337 million. Sensitivity #2 is the same as the first sensitivity except that both the escalation and interest rates increase 1.5% (and thus the real discount rate remains at 5.25%). In this second combined risk scenario, the Ontario Sale benefit is reduced to $581 million.

It should be noted that while the above deals with the possibility of adverse combinations of sensitivities, Manitoba Hydro believes that there is at least an equal likelihood that there would be positive combinations of sensitivities resulting in higher sale benefits than the expected $696 million.

In response to alternative scenarios suggested by various intervenors, Manitoba Hydro filed Exhibit #MH-40 which analyzed additional sensitivities of the Ontario Sale benefits using a range of discount rates applied to a wide range of different scenarios regarding DSM levels, thermal life options, and diversity exchange extensions. These sensitivities were summarized by Manitoba Hydro in its final argument (page 71) as follows:

1) +/- 1.5% discount rate.

2) +/- 10% change in capital costs of all projects.

3) Bipole III located on west side of Lake Winnipeg.

4) +/- 20% and +/- 50% interruptible export rates.

5) Sales adjusted for having two interruptible energy markets.

6) Load growth.

7) 2X DSM, no DSM.

8) 5X DSM, 5X DSM ramping to 10X DSM.

9) Extended diversity exchange agreements.

10) Thermal life extension.

11) Greenhouse effect.

12) Combined adverse sensitivity.

13) Stagflation sensitivity.

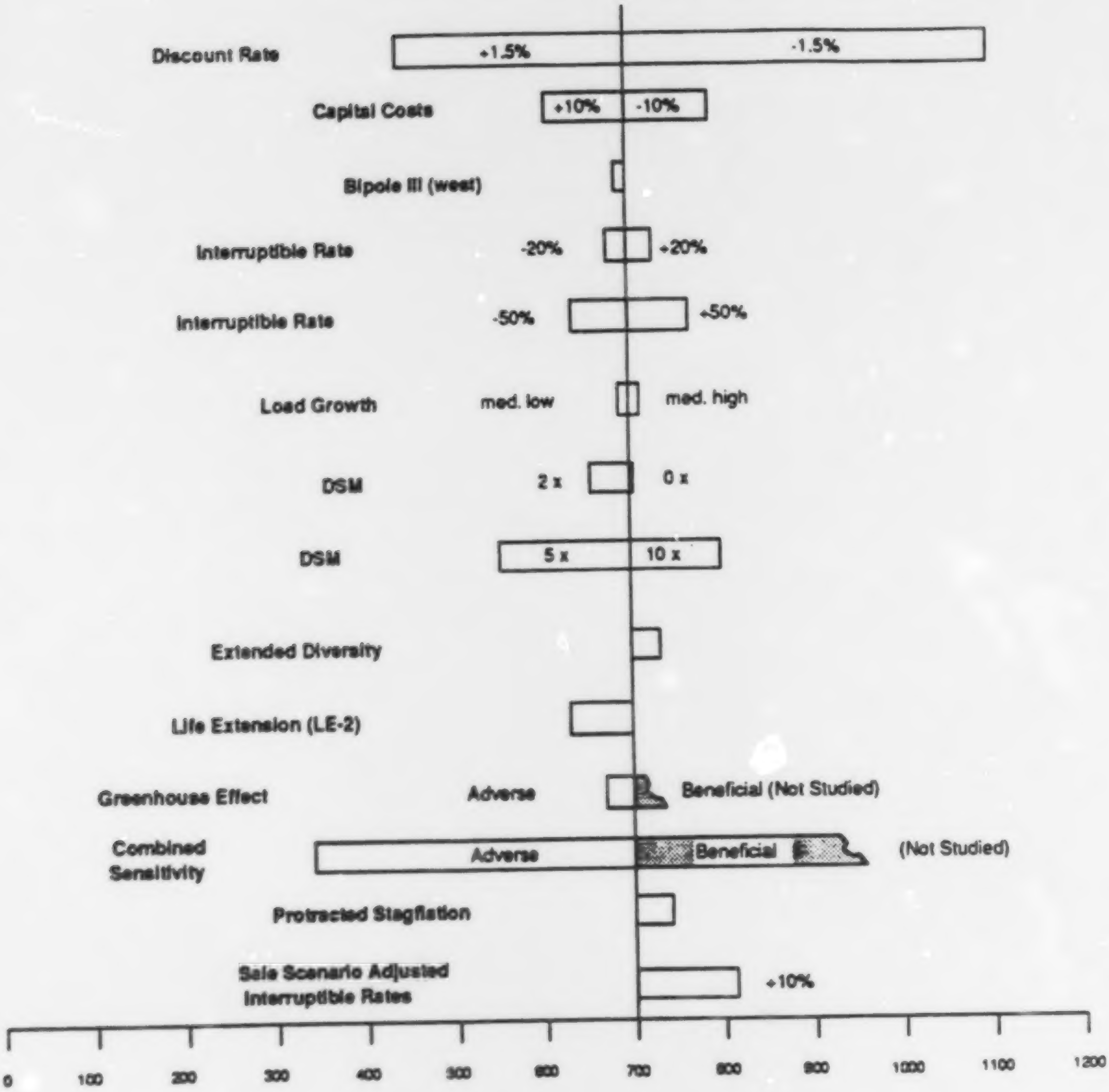
14) Streamflow variability (i.e., droughts, floods).

Manitoba Hydro concluded that the range of sensitivities performed support its opinion that the Ontario Sale is clearly beneficial for the full range of plausible sensitivities.

The following figure entitled, "Summary of Sale Benefit Sensitivities", was filed as part of Manitoba Hydro's closing argument (page 71a) and illustrates the financial effects of the above sensitivities.

Summary of Sale Benefit Sensitivities

(Information Extracted from Previous Evidence)



Ontario Sale Benefits (millions of 1989 P.V. dollars)
Estimate in Original Submission $ 696 million
Current Estimate $703 million

During the public hearing, Board Counsel itemized all the factors in the worst-case scenario assuming that Conawapa and the Ontario Sale proceed. The following table summarizes the components of the worst-case scenario.

The Worst-Case Scenario
In Millions of 1989 Present Value Dollars

	Amount
Present value of benefits of Scenario 1 vs. Scenario 2	$696
Less:	
Costs of constructing Bipole III down west side of Lake Winnipeg	-16
Incorporating cost of 25 basis points for the provincial guarantee (i.e., increasing the real discount rate from 5.5% to 5.75%)	-40
Cost of a 2-year delay in completing Conawapa due to delays in obtaining environmental approvals	-103
Add:	
Costs to bring Scenario 2 transmission reliability up to Scenario 1 level	+50
Worst-Case Present Value of Benefits of Scenario 1 vs. Scenario 2	$587

(Transcript, Volume 18, pages 4136-4153)

The above table is composed of quantified figures obtained during the public hearing. Two observations must be made at this point:

1) If for any reason Manitoba Hydro is unable to negotiate an extension of its presently disputed augmented flow program for Southern Indian Lake, the net benefits of Scenario 1 versus Scenario 2 would be further reduced.

2) Any unquantified environmental costs over and above the quantified costs included in the above table may be quantified at future environmental assessments and would represent a further reduction in the benefits of Scenario 1 versus Scenario 2.

Manitoba Hydro concludes that the risks associated with the Preferred Development Plan are generally manageable and would not be significantly different with any of the alternative scenarios. It is impossible to devise a program that eliminates all risk. However, Manitoba Hydro believes that, under a broad range of possible future events, its Preferred Development Plan is the best means of assuring an adequate and economic supply of power to Manitoba customers.

Position of Independent Witnesses and Intervenors

GWC

On page 25 of his pre-filed testimony, GWC noted that "apart from the sensitivity analyses which illustrate the effect on rates of changes in the assumptions, no evidence is presented that attempts to quantify any of the risks that have been identified". Manitoba Hydro subsequently filed its Rebuttal Evidence and Risk Management and Exposures documents (Exhibits #MH-3A and MH-3B) in response to the concerns raised by GWC and other intervenors.

During his cross-examination at the public hearing, GWC testified that he had read Manitoba Hydro's risk document noting that Manitoba Hydro had attempted to address the risk issues and this provided him with some comfort.

(Transcript, Volume III, page 3109)

WRA

In WRA's pre-filed testimony (page 8), he noted that "many of the risks associated with the preferred plan . . . arise from provisions in the System Participation Agreement such as the provisions governing payment, design of rates, force majeure, Deferred Energy, Supplemental Energy, and performance standards". These concerns are addressed by the Board in the previous section entitled, "Contracts with Ontario Hydro".

CAC/MSOS

CAC/MSOS initially contended that the issue of risk had not been subsequently addressed in Manitoba Hydro's Submission. Manitoba Hydro subsequently filed a document entitled, "Risk Management and Exposures" (Exhibit #MH-3A). Late in the hearing process, CAC/MSOS retained Dr. Lemberg, a risk management consultant, to review the adequacy of Manitoba Hydro's risk assessment.

On page 8 of his pre-filed testimony, Dr. Lemberg concluded that "the Board cannot determine the riskiness of the Preferred Development Plan because there is no meaningful analysis of the risks".

During his cross-examination however, Dr. Lemberg admitted that he had not had time to go into great depth into Manitoba Hydro's Submission and the additional evidence filed during the public hearing because there just was not time from the date he was retained to the date he appeared as a witness:

> "So, the honest answer is I haven't had time to go into great depth, and secondly, doing it from a distance or from the other side of the table in a short time is difficult, so I'm left with commenting on what I've seen, relying on qualitative and experience, characterizations of risk, identifying risky things, and that's about it."

(Transcript, Volume 15, pages 3449-3450)

Manitoba Hydro noted in its closing argument that Dr. Lemberg's concerns had already been considered as follows (pages 116-119):

1) Risk of Capital Cost Overruns

   Manitoba Hydro noted that page 9 of Appendix B of Appendix VII of its Submission indicates that its Preferred Development Plan has a benefit/cost ratio of 1.77 even with "un-indexed" construction costs at +30%.

2) Risk of Capital Cost Overruns Combined with Delays

   Manitoba Hydro studied a number of combinations of adverse events in its "worst-case" scenarios. In particular, the cost of delay was estimated and does not change Manitoba Hydro's conclusion that "un-indexed" cost overruns would still leave its Preferred Development Plan economic and preferable.

3) Delay in Obtaining Environmental Approvals

   Manitoba Hydro filed Exhibit #MH-35 during the public hearing to address the environmental regulatory risks in regards to obtaining environmental approvals. Exhibit #MH-35 was previously discussed in the section entitled, "Evaluation of Key Scenarios", under the heading, "Environmental Evaluation".

4) Escalation in Construction Costs

   Manitoba Hydro noted that the Hydro-Electric Generation Stations Cost Price Index (HEGSCPI) is expected to reflect substantially any actual escalation of construction costs for Conawapa and Bipole III.

5) Risk of Litigation

The risk of potential litigation was discussed by Manitoba Hydro in its Risk Management and Exposures document (Exhibit #MH-3A) which considered its impact on delays at the beginning and end of the project.

6) Risk that Ontario Hydro Schedules the Minimum Energy Permitted

   Manitoba Hydro noted that the situation whereby Ontario Hydro schedules the minimum energy permitted under the terms of the System Participation Agreement is in fact its base case. All of Manitoba Hydro's evaluations were based on Ontario Hydro scheduling the minimum 65% permitted in all years of the Ontario Sale period.

7) Dispute over Which Consumer Price Index to Use

   Manitoba Hydro stated that the contract with Ontario Hydro refers to the "Consumer Price Index for Canada, All Items - Not Seasonally Adjusted". There is no dispute or possible misunderstanding as to which index applies under the System Participation Agreement.

8) Risk of Disputes

> Manitoba Hydro noted that if there should be any dispute, the parties would have recourse to the contract's mechanism for resolution of disputes. Any effect on revenues would depend on the resolution of the dispute.

CAC/MSOS' final position was summarized as follows:

> "In summary, CAC/MSOS is not concerned about the concept of a sale of power to Ontario Hydro per se; it is concerned about (i) the timing built into the existing contract, (ii) the resulting risks for consumers stemming from the penalties for later termination of the contract and from possible losses due to late completion, and (iii) the adequacy of the rewards given the risks that consumers will be involuntarily required to bear."

(CAC/MSOS, Written Argument, page i)

When discussing whether the Ontario Hydro contract should be approved, CAC/MSOS further discussed the risk/reward relationship:

> "What sort of reward is adequate to compensate for such risks? Neither Manitoba Hydro nor Mr. Osler seemed willing to provide any benchmark. In Manitoba Hydro's case, although the President and the Chairman set out three criteria which were used for negotiating the contract, they appeared indifferent to whether such criteria were met today, as if it no longer made a difference. Indeed, Mr. Ransom even speculated that had the Manitoba Hydro Board known at the time it approved the contract that the 2:1 ratio of revenues to costs would have fallen below 1.8, it might still have approved the deal. Likewise, Manitoba Hydro seemed unwilling to offer any firm rate of return criterion and appeared to back away from the 10% rate set for negotiation purposes. This attitude begs the question whether we can do without a hurdle rate or test of acceptability".

(CAC/MSOS, Written Argument, page 43)

CAC/MSOS then argued that the 10% rate of return used by Manitoba Hydro was "at the low end of the range:

> "In the absence of a no risk contract, involuntary risk takers have the right to ask for a large risk premium in order to make the rewards large relative to the risks - higher than the normal returns for voluntary investors in the market. In our judgment 10% is inadequate. Given the circumstances of Manitoba Hydro, a higher standard - at least 15% real return - should be met in order for the sale to be permitted to proceed".

(CAC/MSOS, Written Argument, page 48)

CAC/MSOS concluded that a 15% real rate of return could be achieved, at least theoretically, by negotiating a new contract.

> "We accept without question Mr. Ransom's evidence, as cited by Manitoba Hydro in final argument (page 90), that it would be impossible for Manitoba Hydro simply to go back to Ontario Hydro to ask for more money or less risk. Both parties to a contract would take the position that a deal is a deal and not subject to renegotiation. However, it is a term of the contract that it will not proceed unless Manitoba Hydro receives a satisfactory report from this Board. Should the Board report that the rewards are inadequate in light of the risks, that would end the contract, if Manitoba Hydro chose not to waive that provision. Terminating the existing contract would leave open the possibility of negotiating a new contract with either higher rates or lower risks for Manitoba Hydro, or both. This course of action, we believe, is a real possibility."

CAC/MSOS, Written Argument, page 48)

Manitoba Hydro responded to the question of risk in its final argument and stated:

> "Various intervenors have suggested that elements of the preferred development plan, particularly the Ontario sale, create unacceptable risks for Manitoba rate payers. Manitoba Hydro does not consider this concern to be justified".

(Manitoba Hydro, Written Argument, page 80)

> "The Preferred Development Plan reduces rather than increases risk to ratepayers through the sale agreement's take or pay provisions and its protection clauses against increases in interest and escalation. The sale revenues help pay for a plant that would ultimately have to be built with or without the sale."

(Manitoba Hydro, Written Argument, page 81)

Manitoba Hydro also address various types of risk that had been addressed in various exhibits including Exhibit #MH-20 and Exhibit #MH-3A. The table on page 15-9 indicates that if load growth was increased by 240 MW, the Ontario Sale benefit would amount to $679 million in 1989 present value dollars. If load growth was decreased by 240 MW, the Ontario Sale benefit would still amount to $652 million in 1989 present value dollars. Therefore, fluctuations in load growth would not significantly negate the total benefit of the Ontario Sale. The table on page 15-9 also illustrated that if all capital costs increased by 10%, the Ontario Sale benefit would still amount to $604 million in 1989 present value dollars. Finally, Manitoba Hydro's sensitivity analyses demonstrate that if its cost of debt increased to 12.1% and thereby increased its real discount rate to 6.75%, the Ontario Sale benefit would total $444 million in 1989 present dollars. Furthermore, if Manitoba Hydro's cost of debt increased to 15.5% and thereby increased its real discount rate to 10%, the Ontario Sale benefit would still be positive at $82 million in 1989 present value dollars.

CSC

CSC stated the following concerns:

> ".....Manitoba rate payers are left fully at risk for variance in the cost of plant built to serve export loads. In addition, the Ontario Hydro contract will increase power system planning risks because it will result in an early commitment to Conawapa, reducing Manitoba Hydro's flexibility to respond to changing circumstances.
>
> .....the higher risks relate to construction overrun, unexpected changes in load, the possible rejection by Ontario of the contract and its implications."

(CSC, Written Argument, pages 42-43)

Manitoba Hydro responded to these concerns in its Risk Management and Exposures document which was filed as Exhibit #MH-3A during the public hearing as follows:

> "On any major construction project, there is always some chance that it will not function as planned and/or it will not be completed on schedule and/or it will cost more than anticipated. During the planning, or pre-commitment stages, these risks are minimized through a variety of activities, some of which are described here.
>
> Extensive site exploration work is conducted. For example, to date, $51.5 million has been expended at Conawapa to determine sub-surface conditions, gravel deposits, hydraulic conditions, topography, environmental considerations, etc., including the construction of a small cofferdam and test excavation in the river bed. Thus, project schedules and estimates, and contract documents can be developed on the basis of thorough knowledge of site conditions, thereby eliminating one of the major, traditional causes of cost or schedule over-runs.
>
> Reputable consultants are engaged to design and estimate the projects. The principal consultants engaged for Conawapa (Crippen-Acres Wardrop) and Bipole III (Teshmont Consultants Inc.) are world-renowned experts in their fields, and have extensive experience with similar projects both in Manitoba and elsewhere.
>
> Project schedules are developed by experienced engineers and technicians using 'state-of-the-art' scheduling techniques.
>
> Cost estimates are prepared by specialist estimators, usually on the basis of detailed quantity calculations and site-specific conditions. In some cases, an independent review of budgets and construction schedules has been commissioned.
>
> Collective agreements involving, among other things, a no strike/no lockout clause, are negotiated with the Allied Hydro Council, representing unionized

> workers who will work at the projects, to ensure that project schedules will not be jeopardized by labour difficulties.
>
> It is considered that the risk of construction schedule or budget over-runs or under-runs is unique to each plant, and essentially independent of the development plan adopted. That is, Conawapa will cost the same and take the same length of time to construct, whether sequence 1, sequence 2, or any other scenario is pursued."

(Exhibit #MH-3A, pages 14-16)

In addition, the Ontario Hydro contract provides protection against higher capital and operating costs since demand payments are based on the Statistics Canada Construction Index and since energy payments are based on the Consumers Price Index.

MIPUG

MIPUG came to the conclusion that Manitoba Hydro's risk analysis indicates that the Ontario Sale is more attractive than the no sale case:

> "MIPUG submits that Manitoba Hydro's initial submission failed to provide adequate information and assessment with respect to the risk issue, and that this matter has accordingly received considerable attention in interrogatories, additional Manitoba Hydro evidence, the submissions of certain experts, and the subsequent testimony provided during the hearings. MIPUG submits that the Board now has before it the analysis required to consider all of the relevant risks."

(MIPUG, Written Argument, page 7)

> "Manitoba Hydro's analysis has identified certain factors (capital costs, interest and water flows) as distinguishing risk features of the Ontario Sale option (namely relative to the no sale option); however, assessment of cumulative adverse situations involving these (and other) factors still indicated the sale case to be more attractive than the no sale case."

(MIPUG, Written Argument, page 20)

NFC

NFC concluded in its closing argument that although there are risks involved, Manitoba Hydro's Preferred Development Plan is the least cost alternative:

> "In summary, there is sufficient evidence before the Public Utilities Board for there to be substantial concern about the potential for schedule delay to the Conawapa-Bipole III Project. Transmission Line right of way disputes, environmental assessment processes, and disputes arising out of Manitoba Hydro's unmet obligations from past developments may all combine to delay Manitoba Hydro's

> planned timetable. On the other hand, the Public Utilities Board has heard evidence to the effect that even with a delay of a year (or possibly even more) in service dates for Conawapa-Bipole III, Manitoba Hydro's preferred scenario remains the least cost alternative."

(NFC, Written Argument, pages 13-14)

Board Findings

In previous sections of this report, the Board Findings indicate that for various reasons, the alternative development scenarios proposed by the independent witnesses and intervenors have been rejected. However, in view of the considerable discussion and importance of risk considerations, the Board considers it necessary to review proposed alternative scenarios as they relate to risk in this section.

During the proceedings, the discussion of risk tended to focus on the Manitoba Hydro Preferred Development Plan with particular emphasis on construction, operating and financial risk. Order-in-Council No. 177 requires the Board to consider risk from all causes (paragraph 1 (d)(iv). Further, the board considers that some risk is inherent in any course of action, or inaction, and that it is necessary to weigh the risks of the Manitoba Hydro preferred development plan against those of the leading alternatives proposed by Manitoba Hydro and intervenors.

For this purpose, the Board will consider risks under three broad categories:

1) Reliability.

   Reliability in this context concerns the ability of Manitoba Hydro to serve its domestic load and meet its contractual responsibility for exports.

2) Construction and Operating.

   Construction and operating risks include cost over-runs, completion delays, changes in the cost of money, goods and services, and all unforeseen events which might reduce revenue or increase cost of system operation.

3) Environmental.

   Environmental risks are assumed to include failure to secure environmental approvals, unexpected project costs entailed in mitigation or compensation of environmental impacts and any social costs of environmental impacts not internalized to the utility.

These categories are not independent, because both environmental and reliability risks could affect construction and operating costs, but they will suffice for the purpose of scenario comparisons.

The Board considers it sufficient to include four scenarios in the comparison of risk; Manitoba Hydro's Preferred Development Plan, Scenario 2 without the Ontario Sale, a scenario postulating the Ontario Sale in 2010 (CAC/MSOS 2010 Scenario), and a scenario outlined by CSC involving no major hydro construction until 2022 (CSC 2022 Scenario). These can be regarded as sufficiently representative of the many variations discussed during the public hearing.

The CAC/MSOS 2010 Scenario was based on achieving three times DSM, extending the life of existing thermal plants and negotiating an Ontario sale in 2010 under terms and conditions no less favourable than those of the present contract. CAC/MSOS argued that it would capture all but $278 millions of the benefits of the Manitoba Hydro Preferred Development Plan and would greatly reduce the risks inherent in an immediate commitment to Conawapa and the Ontario Sale.

The CSC 2022 Scenario relied on achieving five times DSM, assuring the life of thermal plants, re-runnering of Kettle, basing system energy capability on 15 percentile flows rather than low flows and purchasing of 100 MW or using gas turbines, in order to delay construction of the next major hydro plant to the year 2022.

A. Reliability

Manitoba Hydro has a statutory duty to provide for the continuance of a supply of power adequate for the needs of the province. The testimony, which the Board accepts, is that this requires the maintenance of a 12% capacity reserve and an energy capability sufficient to supply the firm energy requirement under low water conditions (Exhibit #MH-2A, pages 21-22). Whatever other attributes a particular development plan may have, it must satisfy this requirement. Whether the plan will do so depends on the system demand and energy requirement. The load forecast thus assumes critical importance in the context of reliability risks.

Over-estimation of future loads could lead to surplus capacity, at worst entailing the sale of firm energy at economy prices with loss of potential income. Under-estimation could entail risk of inadequate capacity threatening Manitoba Hydro's ability to fulfil its statutory and contractual commitments. The magnitude of such risks would depend on the rate of divergence between forecast and actual loads: a slow divergence would allow time for revision of development plans while a rapid divergence would not.

Error in estimating the potential for DSM savings must be considered in conjunction with error in load forecasts. Most intervenors considered Manitoba Hydro's estimate of 100 MW to be too low.

A distinction must be made between a DSM target in the sense of an objective and a figure to be used for planning purposes. The Board completely supports the principle that the economic potential of DSM should be fully exploited to the extent that this can be done without disbenefit to society, Manitoba Hydro or its customers, and for that reason believes that Manitoba Hydro should set its sights high. However, the figure appropriate for planning purposes should be neither more nor less conservative than all the other planning assumptions. Using an optimistic figure for planning purposes creates risk in the context of reliability.

The same considerations apply to supply side assumptions which may or may not be capable of realization in the uncertain future. It is possible in a technical sense to extend the life of Hydro's thermal plant. Whether it will be economic to do so is less certain, and whether it will be environmentally permissable to do so will depend on the degree to which society may be willing to tolerate avoidable pollution of the atmosphere in future years.

The Board finds that any development plan which depends heavily on supply side resources which Manitoba Hydro may or may not be able to realize carries unquantifiable but nevertheless real reliability risks.

Transmission is another factor in system reliability. Mr. Zaleski testified to the importance of Bipole III and indicated that Scenario 2 with 230 kV transmission from Wuskwatim would provide an unacceptable level of reliability, requiring an additional $45 to $50 million in 1989 present value dollars for 230 KV transmission from the Nelson.

The Board concludes that the alternative scenarios proposed by CAS/MSOS and CSC involve no reinforcement of transmission from northern Manitoba until 2010 and 2022 respectively and indicates that these alternatives have not been fully developed. The intervenors' alternatives rely more heavily on load reduction and additional capacity in southern Manitoba, to some extent reducing the importance of transmission from the north. If all the assumptions on which they are based are in fact realizable, the reliability risks relating to transmission would nevertheless remain at a higher level than those entailed in the Manitoba Hydro Preferred Development Plan.

In addition, the Board notes that the CSC 2022 Scenario based system firm energy capability on 15 percentile flows. Under low flow conditions, the Board envisages that if regulators in other jurisdictions act to limit generation expansion to the level of minimum domestic need, it may be difficult for Manitoba Hydro to find sources of supply under such circumstances. The Board is therefore of the opinion that plans which rely on relaxed planning criteria incur unacceptable reliability risks.

Comparing the four scenarios, the Board finds that the Manitoba Hydro Preferred Development Plan incurs the least reliability risk. Manitoba Hydro's Scenario 2 incurs higher risks, which can be quantified at $50 million in 1989 present value dollars. The CAC/MSOS 2010 Scenario incurs moderate but unquantified reliability risks while the CSC 2022 Scenario incurs unacceptable reliability risks.

The Board concludes that the intervenors' alternative scenarios must be rejected, inter alia, on reliability grounds.

B. Construction and Operating Risk

Many risks of the Manitoba Hydro Preferred Development Plan relating to construction, operation and economic factors were evaluated with results as shown in the sensitivity analyses throughout this section. The risks are shown to be considerable, but in nearly every case, are less than the comparative net benefits. Dr. Lemberg testified to the desirability of further risk analysis. Manitoba Hydro testified that it had analyzed risk, and considered it manageable.

Some risks posed by intervenors were evaluated but not quantified. WRA's testimony raised questions relating to force majeure, lost capacity charges due to the requirement of 95.5% availability, reduction of revenue from deferred energy through operation of the F factor, sale of energy at supplementary rate under spill conditions, and uneven effect on revenue of high and low water conditions.

The Board accepts that force majeure events constitute a risk, but accepts Hydro's position that under the agreement the risk is shared equitably between the parties. The Board notes that 95.5% availability is typical of single Hydro units, but far below the level of system reliability maintained by Hydro. For this reason, it views both force majeure and availability risks as events with a low probability of occurrence. They are both inherent in the Ontario Sale and the related benefits must be large enough to support them.

Mr. Thompson testified that the take or pay provisions of the contract would prevent Ontario Hydro from scheduling deliveries in such a way as to reduce Manitoba's revenue under spill conditions (Transcript, Volume 15, page 3545). The Board agrees with this view.

With respect to the other operating risks cited in the WRA testimony, the record shows that scenario revenues were determined by simulation, and thus already reflect the effect of high and low flow conditions.

The Board finds that Manitoba Hydro's Preferred Development Plan entails relatively large construction, operating and financial risks but that these risks are in general fully capable of being supported by the comparative benefits of the plan.

Manitoba Hydro's Scenario 2 would involve all the construction risk inherent in Scenario 1 related to the construction of new hydro plants, but because the largest plant (Conawapa) would be constructed later, the risks would be somewhat less on a present value basis. On the other hand, risks relating to Conawapa would not be shared by Ontario Hydro but would be borne entirely by Manitoba Hydro. For this reason, the Board finds that the construction, operating and financial risks relating to Scenario 2 are commensurate with those entailed in the Manitoba Hydro Preferred Development Plan.

Environmental Risk

Manitoba Hydro has quantified known environmental and associated costs relating to the Preferred Development Plan.

On a present value basis, failure to secure approval for relaxation of high and low water levels in South Indian Lake would reduce benefits by $25 million (Transcript, Volume 18, page 4136). Rerouting of Bipole III west of Lake Winnipeg would reduce benefits by $16 million (the difference in impact between Scenarios 1 and 2)(Transcript, Volume 18, page 4140). A two-year delay in receiving environmental approvals is estimated to reduce benefits by $103 million (Exhibit #MH-35). The Board notes that this exhibit provides estimates of probability as well as cost; that the most costly sequence of events would be a revocation of license in the winter of 1993/94 with an impact of $255 million, and that the probabilistic cost of all the regulatory risks is $14.05 million at a 50% confidence level, or $25 million at a 90% confidence level. The Board will use the latter figure as a measure of the risk involved.

The Board therefore considers that a reasonable estimate of environmental risk of the Manitoba Hydro Preferred Development Plan is $66 million, and that the inclusion of this figure with construction and operating risk allowances would still result in a considerable net comparative benefit.

In its final argument, the Northern Flood Committee drew a clear distinction between Conawapa, neither opposing nor approving, and other hydro developments on the Nelson and Burntwood Rivers, which it opposed in principle. This, together with the testimony of Dr. Shaffer, suggests to the Board that considerable environmental risk may attach to Scenario 2 in which Wuskawtim is developed first. The same consideration would apply to the CSC alternative, under which some site smaller than Conawapa and presumably on the Burntwood system would be developed when necessary.

In regard to environmental risks posed by the Preferred Development Plan and Scenario 2, the Board concludes, by reason of its observations above with regard to Wuskwatim that the Preferred Development Plan is likely superior to Manitoba Hydro's Scenario 2 in terms of environmental risk.

Alternatives involving thermal life extension involve atmospheric and other impacts as do those predicated on imports, which would entail extra thermal generation. Gas turbines have smaller but non-negligible impacts. Whether risks relating to project costs would attach to these alternatives would depend on environmental policies a decade hence. The Board cannot estimate the extent of the risks involved.

Scenarios in which Conawapa is omitted or delayed also involve atmospheric impacts creating social costs which are not internalized and do not affect the costs and benefits as calculated by Manitoba Hydro. The response to CSC/MH (11) 1 showed a 180,000 tonne reduction in SO_2 if energy supplied under the participation agreement displaces coal-fired thermal generation. Due to the flexibility of scheduling permitted under the agreement, this is considered to be the most likely case, regardless of Ontario Hydro's future development plans.

The Board finds then on the above analysis that the Preferred Development Plan emerges as the proposal least likely to entail substantial environmental difficulties and costs.

All of the four Scenarios reviewed here will likely be subject to unforeseen environmental difficulties which can only be dealt with both as to specifics and costs by environmental hearings.

Board Findings and Recommendations

Early in the public hearing Mr. Ransom, Chairman of Manitoba Hydro, observed that despite Manitoba's long-term planning being amongst the foremost questions of public policy in this Province, there was in the past very little opportunity for informed debate prior to major commitments being undertaken.

This hearing enabled the Public Utilities Board to review Manitoba Hydro's major capital projects during the period 1990 to 2009 with emphasis on those facilities required by the year 2000. The Board was assisted in this review by several groups of intervenors including the Consumers Association of Canada (Manitoba)/the Manitoba Society of Seniors; a group comprising the Concerned Citizens of Manitoba Inc., the Sierra Club of Western Canada (Manitoba) and the Conservative Strategy Association of Manitoba Inc.; the Manitoba Industrial Power Users Group; the Northern Flood Committee, the Community Association of South Indian Lake and Manitoba Keewatinowi Okimakanak Inc. The Board was also assisted by two independent witnesses, George W. Clayton and Whitfield Russell Associates.

The hearing process, assisted by these groups which are representative of a wide section of Manitoba interests, attracted extensive media comment thus enabling many more interested citizens to follow the examination.

The Board believes that the process itself and this report will bring about an enriched public understanding of the importance of the development of electrical power to citizens of Manitoba.

The Board Findings and Recommendations are derived from key sections of the report. These sections were organized so that the Board could follow a step by step decision process which mirrors the way in which a utility itself arrives at decisions on major capital plans of this type.

The Board Findings and Recommendations are:

1) Manitoba Hydro's proposed generation expansion scenarios are consistent with past decisions and commitments made to develop Manitoba's northern river systems.

2) The Board is of the view that it does not have jurisdiction on the interpretations to be given to The Manitoba Hydro Act or The Manitoba Energy Authority Act.

3) The Board does not consider that Manitoba Hydro proposes in any of its scenarios to construct generation facilities solely for export sales.

4) The Board accepts the planning criteria of Manitoba Hydro as being consistent with the practices prevailing in the electric utility industry in Canada.

5) The Board finds that a 12% capacity margin is appropriate for Manitoba Hydro's generation planning purposes.

6) The Board accepts Manitoba Hydro's base case forecasts for the purpose of generation planning.

7) The 100 MW DSM target used by Manitoba Hydro is an appropriate DSM target to use for generation planning purposes.

8) The Board completely supports the principle that the economic potential of DSM should be fully exploited to the extent that such DSM programs are cost-effective.

9) The matter of DSM, particularly as it effects costs of service and rates, will be reviewed by the Board from time to time at future rates hearings.

10) The Board endorses the work necessary by Manitoba Hydro to ensure that the existing thermal plants in Brandon and Selkirk can be relied upon for the remainder of their rated life.

11) The Board recommends that any new thermal plants should be for firming and peaking purposes only.

12) The Board encourages Manitoba Hydro to continue active negotiations with neighbouring utilities to enhance their import/export and diversity agreements whenever possible and economical.

13) Non-utility generation is endorsed by the Board and Manitoba Hydro is encouraged to pursue this supply option vigorously.

14) The Board accepts Manitoba Hydro's outline of hydro-electric supply options as being reasonable and appropriate for generation planning purposes.

15) The Board concludes that any development plan which depends heavily on large DSM savings and on supply-side resources which Manitoba Hydro may or may not be able to realize carries unquantifiable but, nevertheless, real risks in terms of system reliability.

16) The Board concludes that the benefits and risks of the Ontario Sale are the determining factor in deciding between Manitoba Hydro's Scenarios 1 and 2.

17) The Board finds the terms and conditions of the System Participation Agreement to be sufficiently clear and unambiguous.

18) The Board finds the diversity exchange agreements with NSP and UPA, together with any related improvements to the transmission capability with Minnesota, to be reasonable and appropriate initiatives for Manitoba Hydro to proceed with at this time.

19) The Board concludes that the Ontario Sale and its related System Participation Agreement and Facilities Agreement is economically sound.

20) The Board concludes that although the socio-economic evaluation is outside its terms of reference as provided by Order in Council No. 177/90, the decision as to the next generating station does not turn on the results of that evaluation.

21) The Board is of the view that its conclusions as to the environmental evaluation should be limited to estimating; to the degree possible, whether Manitoba Hydro environmental cost estimates for the Preferred Development Plan and Scenario 2 are adequate.

22) The Board is satisfied that the $696 million net benefit of the Preferred Development Plan provides a cushion for substantial unquantified environmental costs.

23) The Board notes that the environmental impacts of Conawapa (under the Preferred Development Plan) versus Wuskwatim (under Scenario 2) are less severe in terms of flooding.

24) The Board accepts Manitoba Hydro's current method of dealing with profits from export sales. This matter will be reviewed by the Board from time to time at rate hearings.

25) The Board considers that some risk is inherent in any course of action, or inaction, and that it is necessary to weigh the risks of the Manitoba Hydro Preferred Development Plan against those of the leading alternatives proposed by Manitoba Hydro and intervenors.

26) The Board finds that the Manitoba Hydro Preferred Development Plan incurs the least reliability risk. The intervenors' alternative scenarios must be rejected, inter alia, on reliability grounds.

27) The Board finds that Manitoba Hydro's Preferred Development Plan entails relatively large construction, operating and financial risks but that these risks are in general fully capable of being supported by the comparative benefits of the plan.

28) The Board finds that on analysis, the Preferred Development Plan emerges as the scenario least likely to entail substantial environmental difficulties and costs.

29) Based on comparisons of net economic benefit, reliability and risk, the Board concludes that the Preferred Development Plan proposed by Manitoba Hydro is the least cost option; that it would result in lower customer rates from 1996 to at least 2027; that it provides the highest level of reliability and the lowest ratio of risk to benefits.

30) The Board endorses those features of the Manitoba Hydro Preferred Development Plan requiring early commitment; specifically the system participation agreement with Ontario Hydro, construction of Conawapa generation station and Bipole III, diversity agreements with NSP and UPA, DSM initiatives and thermal plant life assurance.

31) The Board has not evaluated elements of the Manitoba Hydro Preferred Development Plan scheduled for later years, concluding that they can better be assessed in future reviews. This applies specifically to Wuskwatim.

The Public Utilities Board

- APPENDICES -

REPORT
# of the
PUBLIC UTILITIES BOARD

in respect of

MAJOR CAPITAL PROJECTS
of
MANITOBA HYDRO

VOL. II

November, 1990

Manitoba Hydro

Major Capital Projects
Volume II

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Appendix I
Orders In Council
No. 177/90 and 1119/90

MANITOBA

Order in Council

No. 177

ON MATTERS OF STATE

To The Honourable the Lieutenant Governor in Council

The undersigned, the Minister of Cooperative, Consumer and Corporate Affairs

submits for approval of Council a report setting forth that:

WHEREAS Manitoba Hydro has requested a public review of its proposals in respect of major capital projects required for generation and transmission during the period 1990 to 2009;

AND WHEREAS it is deemed desirable that such a review be undertaken by The Public Utilities Board;

AND WHEREAS section 107 of The Public Utilities Board Act, being chapter P280 of the Continuing Consolidation of the Statutes of Manitoba, provides in part as follows:

> "107 The Public Utilities Board may perform duties assigned to it...
>
> (b) by order of the Lieutenant Governor in Council...."

THEREFORE, We, The Minister recommends that:

1. The Public Utilities Board (the "Board") be assigned the duty of reviewing, at a public hearing, Manitoba Hydro's proposals in respect of major capital projects required for generation and transmission during the period 1990 to 2009, with emphasis on those facilities required by the year 2000. This review shall include consideration of the following:

    (a) the recent agreements signed between Manitoba Hydro and Ontario Hydro to supply Ontario Hydro with a firm supply of power starting in the year 2000;

    (b) the agreements signed between Manitoba Hydro and Northern States Power and United Power Association for diversity exchanges commencing in 1995;

    (c) the effect of the proposed capital projects on the electricity rates to be charged to Manitoba consumers and the methods proposed to phase in these effects, particularly in regard to the construction of Conawapa and its associated transmission lines;

    (d) the necessity of the proposed major capital projects, their physical and engineering characteristics and their economic consequences with emphasis on:

        (i) load forecasts and forecasting methods used, as well as an indication of the relative success of previous forecasts;

        (ii) a description of the process to be used by Manitoba Hydro in the development and implementation of its demand-side management programs;

        (iii) evidence that all reasonable alternative options have been considered and that the proposed capital projects have been selected on reasonable grounds i.e. technical feasibility, cost efficiency, and reliability; and

        (iv) the analysis by Manitoba Hydro of potential risks from all causes - including economic, financial, and technical risks. By reason of the fact that these same capital projects will be the subject of hearings before the Clean Environment Commission, analysis of risks should include possible modifications to the capital projects resulting from the environmental review.

2. The Board shall hear submissions from any persons or groups or classes of persons or groups who, in the opinion of the Board, have an interest in the matter.

3. Manitoba Hydro shall provide the Board and registered intervenors with the following data and evidence the Board deems necessary to conduct the above-noted review:

(a) copies of the agreement between Manitoba Hydro and Ontario Hydro and copies of the agreements between Manitoba Hydro and Northern States Power and United Power Association (collectively called the "Agreements");

(b) evidence as to the nature of the Agreements and their impact on Manitoba Hydro's major capital plans;

(c) the impact of the proposed major capital projects on domestic rates; and

(d) such other evidence as the Board may require to facilitate the review of the items enumerated in paragraphs 1(a) through (d)(iv) herein.

4. Manitoba Hydro shall be responsible for costs to intervenors pursuant to Public Utilities Board Order No. 163/87.

5. The Board will forward its report on its findings to the Lieutenant Governor in Council, and make it public, not later than November 1, 1990.

Initiating Department/Agency	
Department/Agency	Authorized Signer
Approved By C.S.C.	Name
Approved as to form by:	
Name	
Civil Litigation Branch or Legislative Counsel	Initials

Signature ....

IN THE EXECUTIVE COUNCIL CHAMBER, WINNIPEG

Upon consideration of the foregoing report and recommendation Council advises that it be done as recommended.

14th February 1990
Date

President or Presiding Member

AT GOVERNMENT HOUSE IN THE CITY OF WINNIPEG

Approved and Ordered this 14th day of February A.D. 199

Lieutenant Governor

PRF 48A

MANITOBA

ON MATTERS OF STATE

No. 1119

To The Honourable the Lieutenant Governor in Council

The undersigned, the Minister of COOPERATIVE, CONSUMER & CORPORATE AFFAIRS
submits for approval of Council a report setting forth that:

WHEREAS Order-in-Council 177/90 pursuant to section 107 of The Public Utilities Board Act, being Chapter P280 of the Continuing Consolidation of the Statutes of Manitoba assigned to The Public Utilities Board the duty of reviewing, at a public hearing, Manitoba Hydro's proposals in respect of major capital projects as described and make its report on its findings to the Lieutenant Governor in Council by not later than November 1, 1990;

AND WHEREAS The Public Utilities Board has advised that due to unforeseen circumstances the public hearing has been prolonged resulting in a request for Order-in-Council 177/90 to be amended by changing the reporting date from November 1, 1990 to November 30, 1990;

THEREFORE, He, the Minister recommends:

THAT Order-in-Council 177/90 be amended by changing the reporting date from November 1, 1990 to November 30, 1990.

Initiating Department/Agency
epartment/Agency Authorized Officer
CC&CA
Approved By
C.S.C. Finance
pproved as to form by:
M. A. PERREAULT
ed Legislation Branch:
~~Legislative Counsel~~

Signature E Connery

IN THE EXECUTIVE COUNCIL CHAMBER, WINNIPEG

Upon consideration of the foregoing report and recommendation Council advises that it be done as recommended.

31st October 1990
Date

President ~~or Presiding Member~~

AT GOVERNMENT HOUSE IN THE CITY OF WINNIPEG

Approved and Ordered this 31st day of October A.D. 1990

Lieutenant Governor

PSF 40

Appendix II
The Public Utilities Board Hearing Process
The Public Utilities Board Regulatory Process

The Public Utilities Board

HEARING PROCESS

Manitoba
Cooperative,
Consumer and
Corporate Affairs

1781

THE ROLE OF PARTICIPANTS IN A HEARING

Role of the Public Utilities Board

The Public Utilities Board operates under the authority of the Manitoba Legislature. Industries regulated include:

- Gas and Propane utilities;
- Manitoba Hydro;
- Manitoba Public Insurance Corporation (Autopac);
- Manitoba Telephone System;
- Water and Sewer Utilities (Excluding the City of Winnipeg);
- Transit Utilities (Excluding the City of Winnipeg owned system);

The main duties of the Board are to:

- review and set rates, and where applicable;
- review and set terms and conditions of service;
- ensure customers of regulated industries receive safe and adequate service;
- review consumer complaints.

Role of Board Staff and Advisors

Board staff and advisors will:

- assist the Board by ensuring relevant matters are brought fully to the Board's attention;
- assist all parties to a public hearing regarding procedural matters;
- communicate Board decisions to the affected public;

- consult with members of the public on any matter involving the Board.

The Board staff and advisors will not:

- take a position on any application;
- recommend any application for approval or denial;
- assist the public in making their case for or against the applicant.

Role of the Public

Manitobans have the right to voice their concerns regarding public utility services in Manitoba.

All Manitobans can apply to The Public Utilities Board for a decision on a matter of interest that relates to a utility.

It is the right of Manitobans to participate in Board hearings. By taking part, the public assists the Board in arriving at its decisions. Public involvement promotes questions and answers of issues and views that may not otherwise be heard by the Board.

This public participation can be done in two ways:

1. An **Intervenor** is a party who wishes to take a position on the application and:

- may provide information or evidence;
- will regularly attend the hearing;
- may wish to examine or question the applicant;
- will be available to answer questions;
- will provide a closing argument at the end of the hearing.

An Intervenor must register with the Board and complete a registration form

2. A **Presenter** is a party who may wish to make a statement to the Board concerning the application being reviewed. Presenters are entitled to observe the entire hearing but are not required to participate in the same way as an Intervenor. Presenters do not have to register with the Board. It is requested that Presenters notify the Board before or at the start of the Hearing that they would like to make a statement so that time may be set aside to hear their position.

THE HEARING PROCESS

The Hearing Process normally includes the following steps:

- The Application;
- Notice of Hearing;
- Pre-hearing Conference;
- Hearing;
- Board Order;

The Public Utilities Board may also hold a hearing at its own discretion into matters under its jurisdiction. These hearings do not necessarily result from an application.

The Board may also deal with matters on an "interim" basis, subject to a final decision at a later date or, deal with matters, such as consumer complaints, without holding a public hearing.

The Application

The Hearing Process begins when a party or "applicant" applies to The Public Utilities Board for a decision on a matter of interest to the applicant.

An applicant may be:

- a regulated industry;
- a consumer;
- a representative of consumers or special interest groups.

Where the applicant is the regulated industry applying for a change in rates, the applicant must satisfy the Board that such a change is required. No regulated industry can change its rates without Board approval.

Applicants must provide information to support their requests. It is this information which will be examined during the Hearing.

Notice of Hearing

The Board is required to inform the public of matters which will be reviewed at a hearing. Notices of Public Hearings are usually published in daily and weekly newspapers throughout Manitoba. Notices may also be sent to groups (example: individuals or municipalities) which have expressed a current or previous interest in the matter being reviewed.

The Notice will include:

- a brief explanation of the matter being reviewed and if applicable, the impact on the ratepayer;
- the time, date and place of the pre-hearing conference;
- the time, date and place of the hearing;
- the procedures to be followed before and during the hearing.

Pre-hearing Conference

Before the hearing begins, the Board will hold a meeting to:

- finalize what matters may be discussed at the hearing;
- identify interested parties (Intervenors or Presenters);
- set a timetable for the exchange of information between the applicant and interested parties;
- deal with opening motions.

The Hearing

At the beginning of a hearing, the Applicant and Intervenors will summarize their positions following which, the full examination of the application will occur. The entire proceeding is recorded by a court reporter and it is this record that the Board will rely upon to make its decision.

At the end of the examination the Applicant and Intervenors will be given an opportunity to make a final statement. When the hearing is over the Board will consider the evidence and issue its decision.

Board Order

Orders of the Board state the Board's decision or recommendations on a particular matter. The Order is made in writing and is available to all Manitobans. It is a legal document and where appropriate is binding upon the parties affected.

Régie des Services Publics

DEROULEMENT DE L'INSTANCE

Consommations,
Corporations
et Coopératives
Manitoba

MG 1781 Fr.

ROLE DES PARTICIPANTS À L'INSTANCE

Rôle de la régie des services publics

La Régie des services publics rend compte de ses activités à l'Assemblée législative du Manitoba. Les entreprises qu'elle réglemente comprennent les suivantes:

- services de gaz naturel et de gaz propane;
- Hydro-Manitoba;
- Société d'assurance publique du Manitoba (Autopac);
- services d'aqueduc et d'égout (sauf ceux de Winnipeg);
- services de transport en commun (sauf le système appartenant à la ville de Winnipeg).

Les principales fonctions de la Régie sont les suivantes:

- Etablir des tarifs et, s'il y a lieu:
- établir les conditions se rattachant à la prestation des services;
- veiller à ce que les clients des entreprises à tarifs réglementés reçoivent des services sûrs et adéquats;
- étudier les plaintes des consommateurs.

Rôle du personnel et des conseillers de la Régie

Le personnel et les conseillers de la Régie exercent les fonctions suivantes:

- veiller à ce que les membres de la Régie soit pleinement mis au courant de toutes les questions pertinentes;
- aider les participants aux audiences publiques en matière de procédure;

- communiquer les décisions de la Régie aux segments du public qu'elles visent;
- consulter le public au sujet de toute question touchant la Régie.

Le personnel et les conseillers de la Régie n'exercent pas les fonctions suivantes:

- se prononcer à l'égard du bien-fondé d'une demande;
- recommander à la Régie d'accueillir ou de rejeter une demande;
- aider le public à préparer un dossier pour appuyer une demande ou s'y opposer.

■ Rôle du public

Les Manitobains ont le droit de faire connaître leur point de vue concernant les services publics offerts au Manitoba.

Tous les Manitobains peuvent s'adresser à la Régie des services publics pour demander une décision sur toute question se rapportant aux entreprises de services publics.

Les Manitobains ont pleinement le droit de participer aux audiences de la Régie. La participation du public aide la Régie dans son processus décisionnel. Elle donne lieu à des échanges d'idées et à des prises de position dont la Régie ne prendrait possiblement pas connaissance autrement.

La participation du public prend deux formes, soit l'intervention officielle et l'exposé ponctuel.

■ Intervention officielle

1. L'intervention officielle est conçue pour les personnes qui désirent appuyer une demande ou s'y opposer et qui, à cette fin:

- peuvent fournir des renseignements ou des éléments de preuve;
- assisteront à l'ensemble de l'audience portant sur la demande;
- désirent interroger le demandeur;
- seront à la disposition de la Régie pour répondre à des questions;
- présenteront des observations finales au terme de l'audience.

Les intervenants sont tenus de s'inscrire auprès de la Régie en remplissant la formule appropriée.

■ Exposé ponctuel

2. L'exposé ponctuel est conçu pour les personnes qui désirent présenter à la Régie certaines observations concernant la demande à l'étude. L'auteur d'un exposé ponctuel peut assister à l'ensemble de l'audience, mais il n'y participe pas aussi activement que l'intervenant. En outre, il n'a pas besoin de s'inscrire comme tel. Toutefois, la Régie prie les auteurs d'exposé ponctuel de lui faire savoir, au plus tard au début de l'audience, qu'ils ont l'intention de présenter des observations, de manière à ce que l'on puisse prévoir du temps à l'horaire à cette fin.

■ Déroulement de l'instance

L'instance comporte normalement les étapes suivantes:

- le dépôt de la demande;
- la remise de l'avis d'audience;
- la conférence préparatoire;
- l'audience;
- la délivrance de l'ordonnance.

Si elle l'estime indiqué, la Régie des services publics peut également, même en l'absence d'une demande, enquêter et tenir une audience concernant toute question relevant de sa compétence.

La Régie peut aussi délivrer des ordonnances provisoires en attendant d'étudier plus à fond les questions en cause et de rendre une décision définitive. Elle peut en outre tenir des séances à huis clos (en l'absence du public), dans le cas de plaintes provenant des consommateurs, par exemple.

Demande

L'instance est introduite lorsqu'une personne dépose une demande auprès de la Régie des services publics en vue d'obtenir une décision sur une question touchant cette personne.

Peuvent présenter une telle demande;

- les entreprises à tarifs réglementés;
- les consommateurs;
- les représentants de groupes de consommateurs ou d'autres associations.

L'entreprise de services publics qui présente une demande de changement de tarifs doit convaincre la Régie de la necessité du changement envisagé. L'entreprise à tarifs réglementés ne peut, common son nom l'indique, modifier ses tarifs sans l'approbation de la Régie.

Le demandeur doit fournir des renseignements à l'appui de sa demande, lesquels sont étudiés par la Régie au cours de l'audience.

Avis d'audience

La Régie est tenue d'informer le public des demandes ou des questions sur lesquelles elle entend se pencher lors de ses audiences. Elle publie généralement des avis d'audiences publiques dans divers quotidiens et hebdomadaires de la province. Elle peut également envoyer des avis à des groupes, institutions ou particuliers qui manifestent ou ont déjà manifesté leur intérêt à l'égard des questions dont l'étude est prévue.

L'avis comporte les élements suivants:

- une brève explication de la question qui sera étudiée et, le cas échéant, de l'effet qui serait ressenti par les consommateurs du service public en cause;
- la date, l'heure et le lieu de la conférence préparatoire;
- la date, l'heure et le lieu de l'audience;
- la procédure à suivre avant et pendant l'audience.

Conférence préparatoire

La Régie tient une conférence préparatoire à l'audience en vue de:

- établir définitivement les questions qui seront etudiées lors de l'audience;
- établir la liste des entervenants et des auteurs d'exposé ponctuel;
- établir un échéancier s'appliquant à l'échange de renseignements entre le demandeur, les intervenants et les auteurs d'exposé ponctuel;
- traiter des requêtes préliminaires.

Audiece

Le demandeur et les intervenants présentent leur point de vue de manière générale, au début de l'audience, et la Régie procède ensuite à l'étude détaillée des questions en cause. Un sténographe judiciaire est présent tout au long de l'audience afin d'établir la transcription sur laquelle la Régie se fondera pour prendre sa décision.

Une fois l'étude des questions en cause terminée, le demandeur et les intervenants sont invités à présenter des observations finales. Au terme de l'audience, la Régie étudie la preuve présentée et rend sa décision.

Ordonnance

Les ordonnances de la Régie font état de sa décision ou de ses recommandations concernant une question donnée. Elles sont rendues par écrit et tous les Manitobains yont accès. Elles constituent des documents de nature juridique qui, le cas échéant, ont force exécutoire pour les personnes qu'elles visent.

La Régie réexamine ses propres ordonnances:

- soit à la demande du demandeur;
- soit à la demande d'intervenants ou d'auteurs d'exposé ponctuel;
- soit de son propre chef.

Les ordonnances de la Régie peuvent en outre être portées en appel devant la Cour d'appel sur des questions de droit ou de compétence.

Regie des services publics

Pour de plus amples renseignements, communiquez par téléphone ou par lettre avec le personnel de la Régie à l'addresse suivante:

RÉGIE DES SERVICES PUBLICS
280, rue Smith, 2e étage
Winnipeg, (Manitoba)
R3C 1K2

Téléphone: (204) 945-2638

The Public Utilities Board

REGULATORY PROCESS

QUESTIONS AND ANSWERS

Manitoba
Cooperative,
Consumer and
Corporate Affairs

1782

1. *WHO IS ENTITLED TO RECOVER THEIR COSTS FOR PARTICIPATING IN PUBLIC HEARINGS?*

The Board and Applicant's costs are initially charged to the Applicant, and ultimately paid by the consumers in the case of a regulated industry.

An intervenor is entitled to apply to the Board to recover costs from the Applicant. Such applications are considered by the Board, subject to its Order governing Awarding of Costs. This Order sets out the criteria that will be used by the Board in assessing such applications including:

1. financial need;
2. contribution to proceedings;
3. evidence of representing a significant group of consumers;
4. evidence of responsible cooperation with other Intervenors with common objectives.

A copy of the Order is available from the Board's offices. It should be noted that the Board does not award costs to presenters or municipalities.

2. *DO I NEED A LAWYER IF I WISH TO TAKE PART IN THE PUBLIC HEARING?*

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3. *DO WE HAVE TO BE THERE FOR THE WHOLE HEARING?*

No, but Intervenors may be restricted from asking questions that may have already been covered during their absence.

4. *CAN I RECOVER THE COST OF LOST WAGES TO ATTEND THE HEARING?*

No, only out-of-pocket expenses such as travel and meals can be recovered if allowed by the Board.

5. *IS A CONSUMER AS AN APPLICANT LIABLE FOR COSTS?*

Technically, the answer is yes. Accordingly, it is recommended a prior ruling of the Board be obtained.

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Régie des Services Publics

PROCESSUS DE RÉGULATION

QUESTIONS ET RÉPONSES

Consommations,
Corporations
et Coopératives
Manitoba

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L'on peut se procurer un exemplaire de l'arrêté sur les dépens en s'adressant au bureau de la Régie. Veuillez noter que la Régie n'accorde de dépens ni aux auteurs d'exposé ponctuel ni aux municipalités.

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MG 1782 Fr.

Appendix III
Appearances

Appearances

Board Panel

E. J. Robertson, Chairman
D. L. Barrett-Hrominchuk, Member
T. D. Bulloch, Member
W. T. Laird, Member
Catherine Milner, Member

Board Advisors

B. J. McLean, CA
S. A. Wong, CA
G. Baker, P. Eng.
T. Erskine, P. Eng.

Board Counsel

W. C. Gardner, Q.C.
R. F. Peters
A. D. Feller

Board Staff

G. O. Barron
R. B. Ball
D. C. deGraff

Manitoba Hydro-Electric Board (Manitoba Hydro)

Counsel:
R. A. L. Nugent, Q.C.
R. E. Roth, Senior Legal Officer, Manitoba Hydro

Witnesses:
A. B. Ransom, Chairman of Manitoba Hydro
R. B. Brennan, President and Chief Executive Officer, Manitoba Hydro
R. O. Lambert, P. Eng., Executive Vice-President, Manitoba Hydro
P. R. Thompson, P. Eng., Vice-President Facilities Planning, Manitoba Hydro
E. A. Zaleski, P. Eng., Division Manager, Generation Planning, Manitoba Hydro
C. E. Wray, CA, Manager, Financial Planning and Economic Analysis, Manitoba Hydro
G. W. Rose, Manager, Marketing and Energy Management, Manitoba Hydro
K. R. F. Adams, P. Eng., Corporate Planning Officer, Manitoba Hydro
J. Chamberlin, PhD.
M. Shaffer, PhD.

Independent Witnesses

Counsel:
W. G. Ryall

Independent Witnesses:
G. W. Clayton, P. Eng.
J. F. Fairman
W. A. Russell

Consumers Association of Canada (Manitoba)/Manitoba Society of Seniors (CAC/MSOS)

Counsel:
A. J. Roman
R. J. Graham

Witnesses:
J. Todd
R. Lemberg, PhD.

Concerned Citizens of Manitoba Inc./Sierra Club of Western Canada, Manitoba Branch/Conservation Strategy Association of Manitoba Inc. (CSC)

Counsel:
B. J. Pannell
M. G. Finlayson

Witnesses:
I. Goodman
W. B. Marcus

Manitoba Industrial Power Users Group (MIPUG)

Counsel:
L. Campbell, Q.C.

Witnesses:
C. Osler
J. Ross

Northern Flood Committee (NFC)

Counsel:
G. Wood

Witnesses:
J. S. H. Brown, PhD.
R. W. Fenton, PhD.
D. A. Young

Community Association of South Indian Lake Inc. (SIL)

Counsel:
D. M. MacIver

Manitoba Keewatinowi Okimakanak Inc. (MKO)

Counsel:
Moses Okimaw

Witness:
Michael Anderson

Presenters

- Keith Emberley
- Manitoba Chamber of Commerce:
  - Beth Candlish, PhD.
  - Edward F. Glass, P. Eng.
  - Dave McKiel
  - Egon M. A. Stanik
- Manitoba Environmental Council:
  - R. L. "Nick" Carter
  - Wayne Neily
- Cyril Keeper
- Russell Woollard
- The Northern Association of Community Councils:
  - Bob McCleverty
- Grant Wright
- City of Thompson:
  - Mr. MacIntyre, Director of Economic Development
- Thompson Industrial Commission
- Thompson Chamber of Commerce
- Norman Regional Development Corporation

Appendix IV
Glossary of Electrical Terms

Glossary of Electrical Terms

Alternating Current (AC)

Electric current that reverses its direction of flow at regular intervals. This occurs 60 times each second and is referred to as a frequency of 60 cycle. 60 Cycle is provided by all utilities in North America.

Bipolar

Having two poles, one positive and one negative. Manitoba Hydro identify their proposed new High Voltage Direct current (HVDC) line as Bipole III.

Capacity

The amount of power that a piece of equipment, or a group of pieces acting together, can handle or provide. For example, a transmission system may have a transfer capacity of 1,500 megawatts or a generating station may have a capacity of 1,290 megawatts.

Capacity Factor

The ratio of the average load during a specific time period to the rated capacity.

Cogeneration

The combined production of electricity and useful heat. This system is sometimes used by industrial plants that require process heat as well as electrical energy. To maintain the heat output when plant electrical loads are light, the excess electrical energy can be provided to the utility system.

Cycle

A complete round of events, such as electric current flowing in one direction and then reversing its direction. Sometimes referred to as Hertz.

Current

The flow of electricity in a conductor (measured in amperes).

Dependable Energy

The energy available from a hydro-electric generating station or a system, under adverse water conditions (e.g., minimum water flow on record).

Direct Current

Electric current that flows continuously in the same direction.

Direct Current

Electric current that flows continuously in the same direction.

Diversity

The phenomenon of different loads reaching their maximum levels at different times. The demands represented by such loads are said to be "noncoincident". Because of diversity the total demand on a power system at any moment is less than the sum of all its individual loads.

Diversity Exchange

An exchange of power between electric utilities when the power requirements or demand peaks of one occurs at a different time than the other. For example, a diversity exchange between Manitoba Hydro and Northern States Power is possible because the peak requirement of Manitoba occurs in the winter and in Northern States power system in the summer.

Distribution

A system of poles, lines, transformers, etc., to provide power to customers at a voltage level they can utilize.

Energy

The capacity for doing work. Expressed in watt hours, kilowatt hours, megawatt hours, gigawatt hours.

Energy Transfer

Electrical energy transmitted through an inter-utility transfer point.

"F" Factor

The factor that is used in the contract with Ontario Hydro to increase the revenue for Manitoba Hydro during the first years of the contract. This is intended to compensate Manitoba Hydro for the higher costs which they will incur during the early years of operation of a new hydroelectric generating station and tends to eliminate the impact on domestic consumers.

Firm Power

Electric power intended to be available at all times during the period of the agreement.

Frequency

The number of cycles through which an alternating current passes in one second. The Canadian standard is 60 cycles or 60 hertz.

Gigawatt hour (GW.h or GWH)

A unit of bulk energy. A million kilowatt hours.

Heat Rate

A measure of a thermal generating station's thermal efficiency expressed in BTU per net KWH or kilojoules per KWH.

Installed Capacity

The capacity measured at the output terminals of the generating units in a station without deducting station service requirements.

Interruptible Energy

Energy made available under an agreement that permits curtailment or interruption of delivery at the option of the supplier.

Kilovolt (KV)

1,000 volts.

Kilowatt (KW)

Commercial unit of electric power. 1,000 watts, or the amount required to operate 1- - 100 watt light bulbs.

A unit of electrical capacity of a piece or group of pieces of equipment.

Kilowatt hour (KW.h)

Commercial unit of electric energy. 1,000 watts of power operating for one hour. Equivalent to 10 - 100 watt light bulbs operating for one hour.

Load

The amount of electric power or energy consumed by a particular customer, group of customers, or piece of equipment.

Load Factor

The ratio of the average load during a designated period to the peak or maximum load in that same period (expressed as a percent).

Loop Flows

Unscheduled flows of electricity that occur whenever loop circuits are formed by multiple transmission lines, e.g., between utilities. Such flows of power load up transmission systems and may reduce their capacity.

Losses

Energy or power lost in circuits or equipment, mainly in the form of heat, when current flows through the conductors.

Loss of Load Probability

The probability that a power system will be unable to supply all of its load through having insufficient generating capacity available to meet the total power demand (e.g., one day in not more than 10 years).

Megawatt (MW)

A unit of bulk power. 1,000 kilowatts.

Megawatt hour (MW.h)

A unit of bulk energy. 1,000 kilowatt hours.

Peak Demand

The maximum load consumed by a customer or a group of customers or a system in a stated period of time, e.g., one month. The value may be the maximum instantaneous load during the period, or more usually, the average maximum load over a designated short interval during the period.

Power

The rate of delivery of energy. Measured in watts, kilowatts, megawatts, gigawatts.

Power System

All the interconnected facilities of an electric utility.

Reserve Generating Capacity

The extra generating capacity required on any power system over and above the expected peak load. Required in case of unexpected breakdown of generating equipment or in case the actual peak load is greater than forecast.

Run of the River Plant

A hydro-electric generating station having negligible capacity for storage of water. The plant has to run on the flow of the river as it comes.

Seasonal Diversity

The diversity between loads that reach their maximum values at different seasons of the year. Manitoba Hydro's maximum occurs in the winter, whereas the utilities in the south reach their maximum in the summer.

Voltage

The electric force or pressure which causes current to flow in a circuit.

Watt

The unit of electric power. A rate of doing work of one joule per second. Light bulbs are rated in watts representing the amount of power they require.

Winter Peak

The highest load on a power system during the period October to March.

Wheeling

The transmission of power belonging to one utility through the lines of another utility for delivery to a third utility.

Appendix V
Historical Development of Hydro-Electricity in Manitoba

Historical Development of Hydro-Electricity in Manitoba

1900 Minnedosa River Plant

The first hydro plant in Manitoba went into operation on the Minnedosa River in 1900. The plant served the City of Brandon and operated eight months of the year. It was dismantled in 1924.

1906 Pinawa Power Plant

The Pinawa Power Plant was the first hydro-electric power plant on the Winnipeg River and the first hydro-electric plant in Manitoba to operate year-round. Pinawa was retired in 1961 to provide more efficient use of water flows at the Seven Sisters power plant which was completed in 1952.

1911 Pointe Du Bois Hydro-Electric Generating Station

In 1911, Pointe Du Bois was completed by the City of Winnipeg Hydro Electric System at an initial development cost of $3,250,000. More units were added from 1912 through 1926 for a total of 16 units and an operating capacity of 70 megawatts. The plant was later rerated at 72 megawatts and is the oldest plant still operating on the Winnipeg River today.

1913 Dominion Government Studies of the Nelson and Churchill Rivers

A comprehensive geological survey of the Nelson and Churchill River basins was conducted by the Canadian Department of Mines to determine the energy potential of Manitoba's northern river systems. This 1913 report ultimately led to the present development of Manitoba's northern water power resources.

1923 Great Falls Hydro-Electric Generating Station

Located on the Winnipeg River, Great Falls pioneered a number of new design features that have since become common practice in power plant development. The plant initially operated 2 units in 1923. By 1928, all six units were installed for a total plant capacity of 132 megawatts. The plant is still operating today.

1931 Seven Sisters Hydro-Electric Generating Station

The Seven Sisters station went into service in April 1931 and is the largest plant on the Winnipeg River. In 1948, capacity was increased from 45 megawatts to 75 megawatts as the result of channel excavations that raised the forebay and lowered the tailrace. Six more units were installed in 1952 which increased station capacity to 150 megawatts.

1931 Slave Falls Hydro-Electric Generating Station

In August 1931, units 1 and 2 of Slave Falls went into service and produced 17 megawatts of capacity. Units added in 1937, 1938, 1946 and 1948 brought total station capacity up to 68 megawatts.

1936 First Export of Power to the U.S.

In 1936, the Dominion Government issued a license to Manitoba Power Commission to export a limited amount of power to Interstate Power Company serving North Dakota and Minnesota. Manitoba Power Commission's interconnection extended half a mile from Gretna to the International Boundary.

1948 Manitoba Water Power Commission (HOGG) Report

After 15 years of depression and war, the Winnipeg Electric Company and the City of Winnipeg Hydro were experiencing the pressures of an expanding economy. It also became evident that generating capacity would soon become inadequate. In 1947, the provincial government appointed a royal commission headed by Dr. T.H. Hogg to study Manitoba's power industry and to submit a report on the best way to ensure adequate generating capacity. The HOGG report, issued in 1948, recommended that future capital costs of high-cost power development should be merged with existing low-cost power.

1949 Formation of Manitoba Hydro-Electric Board (MHEB)

Following Dr. Hogg's report, the Winnipeg Electric Company, City of Winnipeg Hydro, Manitoba Power Commission and the Manitoba Government finally agreed that a co-ordinated energy policy should be developed to meet the future power requirements of the province. As a result, The Manitoba Hydro-Electric Board was formed in 1949. The MHEB's first responsibility was the construction of a hydro-electric plant at Pine Falls on the Winnipeg River.

1951 Pine Falls Hydro-Electric Generating Station

Pine Falls went into service in 1951. Six units were installed during 1951-52 for a total generating capacity of 82 megawatts.

1952-53 MHEB and WECo. Amalgamate

In 1952, the provincial government authorized The Manitoba Hydro-Electric Board to negotiate with the shareholders of Winnipeg Electric Company to acquire the control and operation of WECo.'s generation and distribution assets. WECo. accepted MHEB's offer and by April 1953, all issued and outstanding common shares of Winnipeg Electric came under the ownership of the MHEB.

1954 McArthur Hydro-Electric Generating Station

McArthur, the smallest plant on the Winnipeg River, completed the development of the Winnipeg River's potential. Eight units were installed during 1954 and 1955 for a total generating capacity of 56 megawatts.

1955 The Transfer of Winnipeg's Distribution Properties

In 1955, The Manitoba Hydro-Electric Board, the Manitoba Power Commission and City of Winnipeg Hydro reached an agreement whereby:

1) all distribution properties in the suburbs owned by City Hydro were sold to Manitoba Power Commission which became the sole distributor of electrical energy in suburban Winnipeg and the rest of the province;

2) all distribution properties in the City of Winnipeg owned by the former Winnipeg Electric Company were sold to City Hydro which now became the sole distributor within the boundaries of the City of Winnipeg.

Under the terms of the agreement, The Manitoba Hydro-Electric Board agreed to supply the additional power requirements of City Hydro.

1956 First Interprovincial Tie-Line

The Seven Sisters-Kenora transmission line, the first interprovincial interconnection, went into service in October 1956 thus connecting the northwestern system of Ontario Hydro and the southern system of The Manitoba Hydro-Electric Board.

1956 Lakes Winnipeg and Manitoba Studies

In 1956, the governments of Manitoba and Canada appointed an agency known as "Lakes Winnipeg & Manitoba Board" to carry out a flood control survey of Lake Winnipeg and Lake Manitoba and all waters flowing into these two lakes. The report, issued in 1958, affirmed that regulation of the lakes would be advantageous to the development of potential generating sites on the Nelson River.

1960 Kelsey Hydro-Electric Generation Station

The Kelsey station was the first plant to be developed on the Nelson River in northern Manitoba. The plant was built to supply the power requirements of the International Nickel Company's townsite and mining, smelting and refining operations at Thompson. The plant went into service in June 1960 and the original installation of five 32,000 kW generators was completed in 1961. Between 1969 and 1972, two more units were added, bringing the station's total capacity to 224 megawatts.

1960 First Manitoba-Saskatchewan Interconnection

A 138-kilovolt tie-line between Brandon Generating Station and Saskatchewan Power Corporation's Boundary Dam thermal plant near Estevan went into service in November 1960. The line was raised to 230 kilovolts in 1968.

1961 Formation of Manitoba Hydro

On April 1, 1961, The Manitoba Hydro Act was passed by legislature to provide for the amalgamation of the Manitoba Power Commission and The Manitoba Hydro-Electric Board. Since that time, Manitoba Hydro has been responsible for the servicing of all Manitobans except for the inner area of Winnipeg, which is served by Winnipeg Hydro.

1963 Nelson River Feasibility Studies

In February 1963, the Province of Manitoba and the Government of Canada entered into an $1.8 million cost-sharing agreement to investigate the feasibility of developing the hydro-electric potential of the Nelson River. The 1964 report was tabled in the Parliament of Canada and in the Manitoba Legislature and led to a second agreement for a $3 million study that was to be completed by 1966. Also in 1963, G.E. Crippen & Associates were commissioned to investigate the economic feasibility of developing the lower Nelson River.

1964 MAPP Agreement

Manitoba Hydro signed a memo of understanding with the Mid-Continent Area Power Planners for possible interconnection lines with American utilities to carry large-scale exchanges of power. At that time, MAPP consisted of 22 public and investor-owned electric utilities operating in the central and north-central states.

1965 Grand Rapids Hydro-Electric Generating Station

The Grand Rapids station, located on the Saskatchewan River, was officially opened in November 1965 with three installed units for a total operating capacity of 330 megawatts. Additional units were installed during 1966-68 which brought total capacity to 472 megawatts.

1966 Development of Nelson River Begins

As a result of the Nelson River feasibility studies that were initiated in 1963, the federal and provincial governments entered into an agreement on February 15, 1966 to jointly undertake the development of the hydro-electric potential of the Nelson River. The federal government agreed to finance the direct current transmission facilities and Atomic Energy of Canada Limited was assigned to act as the federal agent in the construction of the line. In accordance with the agreement, Manitoba Hydro began to develop the Kettle Generating Station on the lower Nelson River.

1967 Nelson Power Connected to Southern System

A 230,000-volt line between Kelsey Generating Station (Nelson River) and the Grand Rapids Generating Station (Saskatchewan River) was completed in 1967. This line connected the southern integrated system with the northern system and established the first link between the Nelson River and the provincial southern grid. The 205-mile line was built primarily to supply International Nickel's new Soab Lake mine 47 miles southwest of Thompson.

1969 Northern Microwave Completed

The final link in a 632-mile microwave system from Winnipeg to Gillam was completed in 1969. The system was a joint venture of Manitoba Telephone System and Manitoba Hydro and was designed primarily for controlling the direct current transmission of Nelson River Power to the south. In addition, the microwave system improved north-south telecommunications and brought live television to northern residents. A second microwave system following a route east of Lake Winnipeg was completed in 1977.

1970 Kettle Hydro-Electric Generating Station

Kettle Station went into service in with one unit on line in 1970. The station was completed in November 1974 with a total plant capacity of 1,272 megawatts. It was the first generating station to be developed on the lower Nelson River and the largest plant to be developed in Manitoba.

1970 U.S.-Manitoba Interchange

In 1970, the National Energy Board granted Manitoba Hydro a permit to establish an interconnection with three large midwestern utilities in the U.S. The 230-kilovolt transmission line from Winnipeg to Grand Forks, North Dakota was completed and placed in service in July for an interchange of power with the Northern States Power Company of Minneapolis, Otter Tail Power Company of Fergus Falls and Minnkota Co-op of Grand Forks. Manitoba Hydro's share of the 145-mile line's total cost of $7.7 million was about $2 million.

1970 Laurie River Hydro Plants Join System

Manitoba Hydro officially took over the plants from Sherritt Gordon Mines Limited in June 1970. The two plants originally went into operation in 1952 and 1958 to supply Sherritt Gordon's mining operations in northwestern Manitoba. The plants have a combined capacity of 10 megawatts.

1970 Development of Lake Winnipeg Regulation Begins

Under the terms of a 1966 federal and provincial agreement, Manitoba Hydro proceeded with the Nelson River development plan which included using Lake Winnipeg as a reservoir. By excavating channels to increase the natural outflow capacity of the lake, and by building a control structure at Jenpeg to regulate the outflow, adequate minimum flows could be guaranteed for hydro sites along the lower Nelson River.

1971 Nelson River EHV Direct Current Line Energized

Extra-High-Voltage direct current twin steel transmission tower lines, constructed by Atomic Energy of Canada Limited under the 1966 federal-provincial agreement, were energized in 1971. Referred to as Bipole I, the lines began transmitting power in June 1972.

1971 Dorsey and Radisson Stations Operational

Construction of the Dorsey Converter Station began in 1968 and became operational in 1971 with the completion of Bipole I. Located near the town of Rosser, Dorsey acts as the southern terminus of the HVDC line. The Radisson Converter Station, located near Gillam, also became operational in 1971. Radisson serves as the northern terminus of the HVDC line. The power generated from the Nelson River stations as alternating current (AC) is converted to direct current (DC) at Radisson for transmission to Dorsey. When the DC reaches Dorsey, it is converted once again to AC for distribution to southern Manitoba.

1972 Second Manitoba-Ontario Tie-Line In Service

In October 1972, a 230-kilovolt line connecting Manitoba Hydro's Whiteshell Station near Seven Sisters with Ontario Hydro's terminal station near Kenora began transmitting power. The line was constructed in accordance with a 1971 agreement replacing the original agreement of 1956. Under the 1971 agreement, Manitoba Hydro would sell Ontario Hydro over $26 million worth of power by April 1978. A subsequent power exchange agreement was made in 1974 for the sale of $47 million worth of surplus power.

1972 Second Manitoba-Saskatchewan Interconnection

A 110-mile, 230-kilovolt high voltage line between Dauphin, Manitoba and Yorkton, Saskatchewan was completed in 1972 to allow an interchange of up to 150 megawatts.

1974 Hydro Begins Nuclear Studies

In 1974, Manitoba Hydro established a small nuclear development department to begin the task of potential site selection.

1975 Two Out of Three Lake Winnipeg Diversion Channels In Use

The control structure in Jenpeg was completed in 1975 and the Eight-Mile and Ominawin Bypass Channels were placed into service. The remaining Two-Mile Channel between Lake Winnipeg and Playgreen Lake was later completed in August 1976. Installations of the first bulb-type turbines to be used in North America began at Jenpeg with the first scheduled to go into service in 1976.

1975 Grand Rapids to Vermilion 230 kV Line Completed

An existing 115 kilovolt line between Brandon and Glenboro was converted to 230 kilovolt operation while an 11-mile 230 kilovolt circuit was completed on the east side of Winnipeg between the Ridgeway and St. Vital transformer stations.

1976 Churchill River Diversion Project Commenced Operation

In September 1976, the project released an initial flow of approximately 10,000 cfs through the Notigi Control Structure. Much of the project was completed in the spring. The main control structure at Missi Falls on the Churchill River channel from Southern Indian Lake was also completed. During the year, work was also completed at Nelson House and Thompson.

1976 Cranberry Portage Extension Energized

A 230 kilovolt extension to Cranberry Portage from Flin Flon was energized in September 1976 bringing central station power to the community of 924 residents. The community of Baker's Narrows, midway along the 30-mile extension from Flin Flon to Cranberry Portage also obtained service.

1976 Agreement Reached on Second 230 kV U.S. Interconnection

Manitoba Hydro reached an agreement with Minnesota Power and Light Company of Duluth to establish an interconnection at the international border in southeastern Manitoba. Manitoba Hydro received a Certificate of Public Convenience and Necessity to build a line from Ridgeway Station to the U.S. border south of Sprague. The 92-mile Manitoba line section was completed in November 1976 and connects with a 200-mile U.S. segment from Duluth, Minnesota. Licenses were also granted for the export of interruptible energy firm power and firm energy during the period November 1976 and October 1982.

1976 Long Spruce on its Way

All major concrete work was completed and construction of the powerhouse was well underway in 1976. The second stage diversion was accomplished and the earth fill section of the main dam was being constructed.

1976 Second Northern Microwave System Begins

In conjunction with the Manitoba Telephone System, work began on a second microwave system into northern Manitoba. The link was constructed on the east side of Lake Winnipeg to provide an alternate route for HVDC control and telecommunications, and to ensure a high degree of reliability for the first and second bipoles. The system was completed in 1977.

1977 Long Spruce

The first 98 megawatt turbine generator went into service in October 1977. By August 1979, all ten units were on line for a total generating capacity of 980 megawatts. The station was officially opened by Premier Sterling Lyon at ceremonies held on June 16, 1979.

1977 Limestone Generating Station

Cofferdamming of the site of the future Limestone Generating Station on the Nelson River was well under way during 1977. The adjacent town of Sundance was established for work on the Henday DC Terminal and work on Limestone and the other generating stations. At the powerhouse site, the upstream leg of the Stage I cofferdam was complete.

1978 Bipole I Completed

Bipole I was completed, bringing the system's transmission capability up to 1,620 megawatts. The majority of design work was completed for Bipole II and installation and commissioning of equipment proceeded.

1978 Nuclear Site Selection Program Deferred

Reduced load growth in the past two years led to a decision to defer the latter parts of the Nuclear Site Selection Program. It was decided that after the Third Report was released in April 1978, which would identify the preferred site (near Lac du Bonnet), nuclear power generation studies would be suspended indefinitely.

1978 Letellier Terminal Installed

The Letellier 230-66 kilovolt terminal was installed to accomodate load growth in southern Manitoba.

1978 Limestone Deferred to 1987

The scheduled in-service date of the Limestone Generating Station was deferred from 1984 to 1987 due to lower-than-expected provincial load growth. As a result, further work on the Lower Nelson project was suspended indefinitely following completion of the Stage 1 cofferdam in October 1978.

1978 Henday Converter Station In Service

With the 1978 completion of the new Henday Converter Station near Limestone, the second HVDC bipolar transmission line went into service. Henday performs the same function as the Radisson station, namely, converting AC to DC for transmission south to Dorsey. Bipole II transmitted power from Henday to Dorsey for the first time in October 1978.

1979 Jenpeg on Line

The last of the six turbine generators at the Jenpeg Generating Station on the upper Nelson River went on line in November 1979. Jenpeg's total rating is 168 megawatts, with a winter capacity of 126 megawatts.

1979 Third Manitoba-Saskatchewan Interconnection

Manitoba Hydro's third interconnection with the Saskatchewan Power Corporation's system went into service in November 1979. The 230-kilovolt line, extending from The Pas to SPC's Squaw Rapids hydro station, improved system stability and increased interchange capabilities for both provinces.

1980 Conawapa and Wuskwatim Studies Underway

Hydro development studies were undertaken on the Conawapa site on the lower Nelson River and the Wuskwatim site on the Burntwood River. Investigative drilling was done at both the Conawapa and Gillam Island sites on the lower Nelson River. Environmental overview studies of the Burntwood River and lower Nelson River were underway.

1980 500 kV Transmission Line Completed

The third U.S. interconnection was completed in 1980. The 500-kilovolt Winnipeg-Minneapolis transmission line more than doubled Manitoba Hydro's interchange capability with the U.S. The completion of this line permitted the delay of future system generation since Manitoba Hydro could rely on power and energy imports during the winter through a seasonal exchange agreement.

1980 MANDAN Letter of Intent Signed

In 1980, Manitoba Hydro and the Nebraska Public Power District signed a letter of intent for the proposed 500-kilovolt MANDAN transmission link between Manitoba and Nebraska. Negotiations continued for the interconnection and for the exchange of seasonal power. This seasonal exchange, like that negotiated with the Northern States Power Company, would permit the construction of future generating facilities in Manitoba to be delayed.

1982 World's First HVDC Research Centre

In January 1982, a complete research centre for HVDC technology opened in Winnipeg. The research centre is a consortium of five sponsoring organizations: Manitoba Hydro, University of Manitoba, Teshmont Consultants, Federal Pioneer Electric Ltd. and the Province of Manitoba.

1982 MANDAN Route Selection

Route selection activities continued on the MANDAN Project, a 500 kilovolt transmission line which would enable energy to be exchanged between Manitoba Hydro and the Nebraska Public Power District on a seasonal basis. In the spring of 1982, the provincial government approved a 32 kilometre-wide macro-corridor from Dorsey Station near Rosser to the U.S. border within which the Manitoba portion of the transmission line will be located.

1983 The Pas-Flin Flon 230 kV Line In Service

A 230-kilovolt transmission line between The Pas and Flin Flon was placed in service in 1983.

1983 Seven Sisters Rehabilitation Completed

The rehabilitation program at the Seven Sisters Generating Station was completed in 1983 below budget at a total cost of $22 million. The restoration program, which began in 1979, extended the life of the plant by another 50 years.

1983 Potential Long-Term Power Sales

Preliminary discussions and studies related to potential major long-term power sales were conducted with members of the Wisconsin-Upper Michigan System (WUMS), the Western Area Power Administration (WAPA) and the Northern States Power Company.

1985 Limestone Gets Go-Ahead

In January 1985, the Premier of Manitoba announced that Manitoba Hydro would call for tenders on the general civil contract for the Limestone Generating Station. In March 1985, the National Energy Board issued a 12-year license to The Manitoba Hydro-Electric Board for the export of firm power and energy to Northern States Power of Minneapolis. The license allows Manitoba Hydro to export a maximum of 500 megawatts of firm power in each 12-month period from May 1, 1993 to April 30, 2005.

1985 Agreement Reached with Ontario Hydro

In March 1985, an agreement was reached with Ontario Hydro to prepare a Letter of Intent for the sale of power. Long-term sales, ranging between 300 and 1,000 megawatts, were expected to begin in the mid-to-late 1990s.

1985 MANDAN Terminated

In March 1985, the Board of the Nebraska Power District of Columbus, Nebraska passed a resolution calling for the termination of the proposed MANDAN transmission line. The main reason cited for the termination was the failure to secure a commitment from the other participating U.S. utilities for cost-sharing arrangements.

1985 Bipole II Reaches Full Power

Bipole II was completed in June 1985, enabling the HVDC transmission line to operate at 1,000 kilovolts (+/- 500 kilovolts nominal). Bipole II adds 2,000 megawatts to transmission capacity.

1985 500 MW Export Approved

The National Energy Board approved a license to the Manitoba Hydro-Electric Board for the export of 500 megawatts of firm power to the Northern States Power Company of Minneapolis, Minnesota for a 12-year period, beginning in 1993.

1985 Planning Studies Continue

Planning studies continued during 1985 for the development of the Conawapa Generating Station on the lower Nelson River; Wuskwatim, Manasan, and First Rapids Generating Stations on the Burntwood River; and Whitemud Generating Station on the upper Nelson River.

1986 New 230 kV Transmission Line Completed

In order to meet the power requirements at a new mine operated by Hudson Bay Mining and Smelting Company Limited, Manitoba Hydro built a 33 kilometre, 230-kilovolt line to Namew Lake.

1986 Upper Mississippi Power Group M.O.U. Signed

In 1986, six U.S. utilities, known as the Upper Mississippi Power Group, signed a memorandum of understanding to study the purchase of power from Manitoba in the 1990s. As part of this understanding, the U.S. utilities and Manitoba Hydro would exchange power on a seasonal basis -- and a new interconnection line would be built.

1987 World's First HVDC Paralleling System Implemented

During the year, the Corporation successfully implemented the world's first commercially operable High Voltage Direct Current paralleling system. A series of tests on Bipole I and II proved that, through the process of paralleling, power transmission from the Nelson River plants could continue even if one of the bipole lines were lost, thereby enhancing system reliability.

1987 New 138 kV Transmission Line to Churchill Energized

In April 1987, a new 138-kilovolt transmission line to Churchill was energized. The $35.6 million project was funded under the terms of the 1984 Canada-Manitoba Subsidiary Agreement on Churchill. Manitoba Hydro's share of the cost was $16.3 million.

1987 Export Agreement Signed with Ontario Hydro

In August 1987, an agreement was signed with Ontario Hydro to supply 200 megawatts of firm power and 5.6 billion kilowatt hours of energy to be delivered under a five-year period from October 1998 to November 2003.

1987 Contract Awarded for Dorsey Converter Station

In September 1987, a $32.6 million contract was awarded to Marine Industries Limited of Montreal for the supply and installation of three synchronous condensers for Dorsey Converter Station, the southern terminus of Manitoba Hydro's High Voltage Direct Current system.

1987 200 MW Diversity Exchange Agreement Signed with NSP

In November 1987, a seasonal diversity exchange agreement for 200,000 kilowatts of capacity and 175 million kilowatt hours of energy each year was signed with Northern States Power Company for the period from November 1996 to October 2016.

1988 Negotiations Continue with Upper Mississippi Power Group

Negotiation continued with the U.S. utilities that form the Upper Mississippi Power Group for a three-part arrangement involving a sale of firm power, a seasonal diversity exchange, and construction of a new high voltage transmission line to the U.S.

1988 New 230 kV Transmission Line Energized

A new 230-kilovolt transmission line between Letellier and the new Stanley Station was energized in October 1988.

1989 Limestone Construction Continues

In June 1989, work began on the removal of the cofferdam in front of the powerhouse and spillway at Limestone. This allowed the Nelson River to flow through the spillway structure and permitted the construction of the south cofferdam. The $1.52 billion Limestone project will add 1,280 megawatts of electricity to the Manitoba system when completed. The first power was delivered in September 1990.

1989 1,000 MW Ontario Hydro Sale Agreement Signed

On December 7, 1989, Premier Gary Filmon and Premier David Peterson signed agreements for the sale of 1,000 megawatts of firm power to Ontario Hydro for 22 years, starting in the year 2000. This development initiative was one of four initiatives announced under Manitoba Hydro's electricity supply plan. The other three initiatives are:

1) 150 megawatt diversity exchange agreements with Northern States Power Company of Minneapolis and United Power Association of Elk River, Minnesota for a total of 300 megawatts;

2) A 100 megawatt target reduction in load forecast through demand-side management by 2001.

3) Rehabilitation work on the Corporation's thermal generating stations in Brandon and Selkirk.

1990 Public Review of Major Capital Projects

Manitoba Hydro's request for a public review of its long term capital plans was endorsed by the Provincial Government by way of Order in Council No. 177/90 which empowered the Manitoba Public Utilities Board to conduct such a review.

Appendix VI
Export Agreements

Export Agreements

Current Export Agreements

Utility	Type	Duration	Amount	Terms
NSP**	Interruptible	1980-1992	19 500 000 MWh	Greater of cost plus 10% or shared cost savings formula.
NSP	Firm Power Sale	1984-1992 (summer)	200 MW at 20% monthly Capacity Factor	Rates negotiated 3 years prior to delivery.
NSP	Firm Power Sale	1993-1996 (summer)	200 MW at 20% monthly Capacity Factor	Negotiated formula.
NSP	Diversity Exchange	1980-1992	300 MW at 20% Capacity Factor	No charge for capacity. Energy at greater MAPP* peaking power rate at time of delivery or supplier's cost plus 10%.
NSP	Firm Power Sale	1993-2005	500 MW at 75% annual Capacity Factor	Capacity Charge at 80% of NSP's Sherco Thermal plant. Energy charge at 80% of Sherco's variable costs.
NSP	Diversity Exchange	1996-2016	200 MW at 20% Capacity Factor	No charge for capacity. Energy at 16.5 mills/kWh (U.S.) escalated from 1988.
Ontario Hydro	Firm Power Sale	1998-2003	200 MW at 80% annual Capacity Factor	Negotiated Formula.
Minnkota	Interruptible	Ongoing	As available	Negotiated formula based on MAPP* rates.

Utility	Type	Duration	Amount	Terms
OTP***	Interruptible	Ongoing	As available	Negotiated formula based on MAPP* rates.
UPA****	Interruptible	Ongoing	As available	Negotiated formula based on MAPP* rates.
SaskPower	Interruptible	Ongoing	As available	Negotiated formula based on MAPP* rates.
Ontario Hydro	Interruptible	Ongoing	As available	

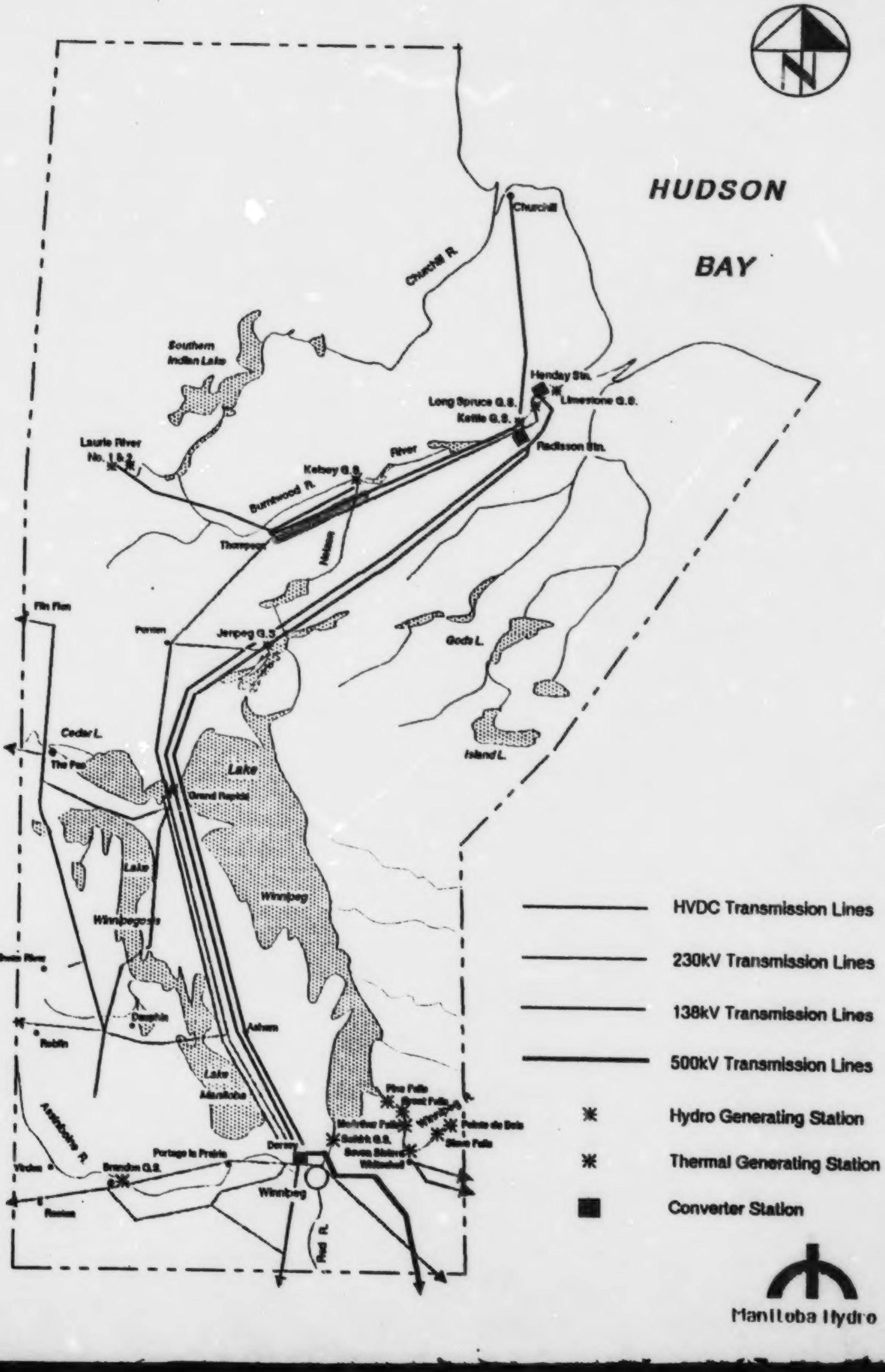
New Export Initiatives

Utility	Type	Duration	Amount	Terms
Ontario Hydro	Firm Power Sale	2000-2022	Steps up to 1 000 MW at 65% Annual Capacity Factor	Negotiated formula.
NSP	Diversity Exchange	1995-2015	150 MW at 20% Capacity Factor	No charge for capacity. Energy at 16.5 mills/kWh (U.S.) escalated from 1988.
UPA	Diversity Exchange	1995-2015	150 MW at 20% Capacity Factor	No charge for capacity. Energy at 16.5 mills/kWh (U.S.) escalated from 1988.

* Mid-Continental Area Power Pool.
** Northern States Power Company.
*** Otter Tail Power.
**** United Power Association.

Appendix VII
1990 Generation and Transmission System in Manitoba

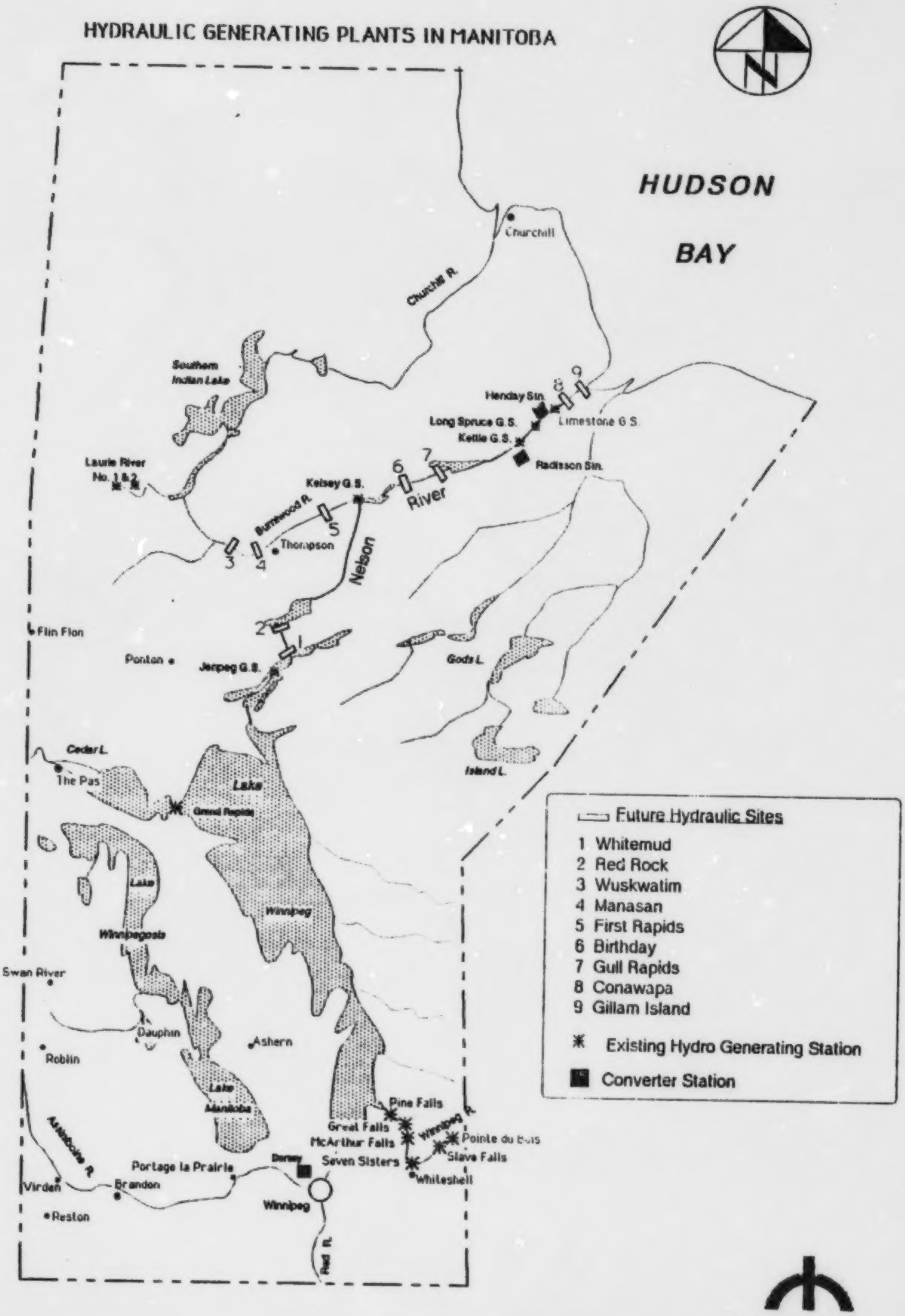
1990 GENERATION AND TRANSMISSION SYSTEM IN MANITOBA


HUDSON
BAY
Churchill
Churchill R.
Southern Indian Lake
Henday Stn.
Long Spruce G.S.
Limestone G.S.
Kettle G.S.
Radisson Stn.
Laurie River No. 1 & 2
Kelsey G.S.
River
Burntwood R.
Thompson
Nelson
Flin Flon
Ponton
Jenpeg G.S.
Gods L.
Cedar L.
The Pas
Grand Rapids
Lake
Winnipeg
Island L.
Lake
Winnipegosis
Swan River
Dauphin
Roblin
Ashern
Lake
Manitoba
Assiniboine R.
Portage la Prairie
Dorsey
Pine Falls
Great Falls
McArthur Falls
Winnipeg R.
Pointe du Bois
Slave Falls
Selkirk G.S.
Seven Sisters
Whiteshell
Virden
Brandon G.S.
Reston
Winnipeg
Red R.
HVDC Transmission Lines
230kV Transmission Lines
138kV Transmission Lines
500kV Transmission Lines
Hydro Generating Station
Thermal Generating Station
Converter Station

Manitoba Hydro

Appendix VIII
Hydraulic Generating Plants

HYDRAULIC GENERATING PLANTS IN MANITOBA


HUDSON
BAY
Churchill
Churchill R.
Southern Indian Lake
Laurie River No. 1 & 2
Henday Stn.
Long Spruce G.S.
Kettle G.S.
Limestone G.S.
Radisson Stn.
Kelsey G.S.
Burntwood R.
Thompson
Nelson
River
1
2
3
4
5
6
7
8
9
Flin Flon
Ponton
Jenpeg G.S.
Gods L.
Island L.
Cedar L.
The Pas
Lake
Grand Rapids
Winnipeg
Lake
Winnipegosis
Swan River
Dauphin
Ashern
Roblin
Lake Manitoba
Assiniboine R.
Pine Falls
Great Falls
McArthur Falls
Winnipeg R.
Pointe du Bois
Slave Falls
Seven Sisters
Whiteshell
Dorsey
Portage la Prairie
Brandon
Virden
Reston
Winnipeg
Red R.
Future Hydraulic Sites
1 Whitemud
2 Red Rock
3 Wuskwatim
4 Manasan
5 First Rapids
6 Birthday
7 Gull Rapids
8 Conawapa
9 Gillam Island
Existing Hydro Generating Station
Converter Station

Manitoba Hydro

Appendix IX
GWC's Alternative Supply Scenario
(Source: Page 22 of Manitoba Hydro's Rebuttal Evidence)

Costs of Plant Order Proposed by G.W. Clayton
as compared to PUB Sequence #2

- costs in millions of $1989
- 1989 Base Load Forecast
- 5.25% Discount Rate

CASE	SEQUENCE		MOSES Total Sequence Cost	Difference from PUB Sequence #2
PUB Sequence #2 Thermal Life Assurance LA-1	LA-1	W-02, C-10, B-17, M-23, FR-27	1259	-
Thermal Life Extension Natural Gas Real Escalation = 3% 2.09 $88/mcf 14.01 M$88 Demand Charge	LE-1	ECT-02, W-10, CL1-14, B-14, CL2-17, C-20	1365	106
	LE-2	ECT-09, W-10, CL1-14, B-14, CL2-17, C-20	1296	37
Thermal Life Extension Natural Gas Real Escalation = 2% 2.09 $88/mcf 14.01 M$88 Demand Charge	LE-1	ECT-02, W-10, CL1-14, B-14, CL2-17, C-20	1349	90
	LE-2	ECT-09, W-10, CL1-14, B-14, CL2-17, C-20	1283	24
Thermal Life Extension Natural Gas Real Escalation = 1% 2.09 $88/mcf 14.01 M$88 Demand Charge	LE-1	ECT-02, W-10, CL1-14, B-14, CL2-17, C-20	1336	77
	LE-2	ECT-09, W-10, CL1-14, B-14, CL2-17, C-20	1273	14
Thermal Life Extension Natural Gas Real Escalation = 1% 3.5 $90/mcf No Demand Charge	LE-1	ECT-02, W-10, CL1-14, B-14, CL2-17, C-20	1248	-11
	LE-2	ECT-08, W-10, CL1-14, B-14, CL2-17, C-20	1218	-41

Note: 1) Firm Sale and Diversity Exchange revenues, interconnection costs, and DSM costs are not included.

Legend:
ECT = 200 MW Combustion Gas Turbine
C = Conawapa
B = Birthday
M = Manasan
FR = First Rapids
CL1, CL2 = 200 MW Coal Plant

LA-1 = Thermal Life Assurance One
LE-1 = Thermal Life Extension One
LE-2 = Thermal Life Extension Two

8/15/90

Appendix X
CAC/MSOS' Alternative Supply Scenarios
(Source: CAC/MSOS' Pre-Filed Testimony)

Table 8-7: MH Scenario 2 with Thermal Life Assurance LA-2 (Capacity)

Year	Added Thermal Capacity (1)	Capacity Resources (2)	Capacity Demand (3)	Surplus/ Deficit (4)	Additional Hydraulic Plants (5)	Augmented Capacity Resources (6)	Capacity Demand (7)	Surplus/ Deficit (8)
1990		4503	3977	526		4503	3977	526
1991		5143	4045	1098		5143	4045	1098
1992		5531	4135	1396		5531	4135	1396
1993		5205	4804	401		5205	4804	401
1994		5213	4911	302		5213	4911	302
1995		5559	4960	599		5559	4960	599
1996		5796	5024	772		5796	5024	772
1997		5816	5132	684		5816	5132	684
1998		5830	5449	381		5830	5449	381
1999		5838	5531	307		5838	5531	307
2000	132	5843	5638	205		5843	5638	205
2001	132	5847	5686	161		5847	5686	161
2002	132	5850	5760	90		5850	5760	90
2003	132	5853	5605	248		5853	5605	248
2004	132	5857	5686	171		5857	5686	171
2005		5597	5237	360		5597	5237	360
2006		5496	5325	171	180	5676	5325	351
2007		5500	5372	128	340	5840	5372	468
2008		5504	5486	18	340	5844	5486	358
2009		5508	5547	-39	340	5848	5547	301
2010		5512	5634	-122	340	5852	5634	218
2011		5516	5717	-201	535	6051	5717	334
2012		5520	5799	-279	965	6485	5799	686
2013		5524	5882	-358	1570	7094	5882	1212
2014		5528	5965	-437	1570	7098	5965	1133
2015		5202	6088	-886	1570	6772	6088	684
2016		4986	6197	-1211	1570	6556	6197	359
2017		4990	6280	-1290	1737	6727	6280	447
2018		4994	6363	-1369	1985	6979	6363	616
2019		4998	6446	-1448	2110	7108	6446	662
2020		5002	6528	-1526	2110	7112	6528	584
2021		5006	6611	-1605	2110	7116	6611	505
2022		5010	6694	-1684	2110	7120	6694	426
2023		5014	6777	-1763	2110	7124	6777	347
2024		5018	6860	-1842	2170	7188	6860	328
2025		5022	6943	-1921	2305	7327	6943	384
2026		5026	7026	-2000	2305	7331	7026	305
2027		5030	7109	-2079	2390	7420	7109	311
2028		5034	7192	-2158	2530	7564	7192	372

NOTES: Derived from Table 8-3.

Life assurance (LA-2) eliminates the capacity deficit in 2002; hence, no additional generating station is required until 2006 when there is a energy deficit.

Table 8-9: MH Scenario 2 with Thermal Life Extension LE-2 (Capacity)

Year	Added Thermal Capacity (1)	Capacity Resources (2)	Capacity Demand (3)	Surplus/ Deficit (4)	Wuskwatim (5)	Conawapa (6)	Birthday (7)	Augmented Capacity (8)	Surplus/ Deficit (9)
1990		4503	3977	526				4503	526
1991		5143	4045	1098				5143	1098
1992		5531	4135	1396				5531	1396
1993		5205	4804	401				5205	401
1994		5213	4911	302				5213	302
1995		5559	4960	599				5559	599
1996		5796	5024	772				5796	772
1997		5816	5132	684				5816	684
1998		5830	5449	381				5830	381
1999		5838	5531	307				5838	307
2000	132	5843	5638	205				5843	205
2001	132	5847	5686	161				5847	161
2002	132	5850	5760	90				5850	90
2003	132	5853	5605	248				5853	248
2004	132	5857	5686	171				5857	171
2005	132	5729	5237	492				5729	492
2006	237	5733	5325	408				5733	408
2007	237	5737	5372	365				5737	365
2008	237	5741	5486	255				5741	255
2009	237	5745	5547	198				5745	198
2010	237	5749	5634	115	180			5929	295
2011	105	5621	5717	-96	340			5961	244
2012	105	5625	5799	-174	340			5965	166
2013	105	5629	5882	-253	340	195		6164	282
2014		5528	5965	-437	340	625		6493	528
2015		5282	6088	-806	340	1230		6772	684
2016		4986	6197	-1211	340	1230		6556	359
2017		4990	6280	-1290	340	1230	167	6727	447
2018		4994	6363	-1369	340	1230	415	6979	616
2019		4998	6446	-1448	340	1230	540	7108	662
2020		5002	6528	-1526	340	1230	540	7112	584
2021		5006	6611	-1605	340	1230	540	7116	505
2022		5010	6694	-1684	340	1230	540	7120	426
2023		5014	6777	-1763	340	1230	540	7124	347
2024		5018	6860	-1842	340	1230	540	7128	268
2025		5022	6943	-1921	340	1230	540	7132	189
2026		5026	7026	-2000	340	1230	540	7136	110
2027		5030	7109	-2079	340	1230	540	7140	31
2028		5034	7192	-2158	340	1230	540	7144	-48

NOTES: Derived from Table 5-3.

Life extension (LE-2) defers the requirement for the first additional plant to 2010.
The least cost sequence is Wuskwatim (2010), Conawapa (2013), Birthday (2017), Manasan (2024) and First Rapids (2027).

MH Submission, Appendix IX shows that LE-2 is practical and the incremental cost relative to LA-1 is only $24 million (see Tables 3.3 and 3.6 in MH Submission, Appendix IX).

Table 8-11: MH Scenario 2 with Extended Diversity (ED) and Thermal Life Extension LE-2 (Capacity)

Year	Extended Diversity (1)	Capacity Resources (2)	Capacity Demand (3)	Surplus/ Deficit (4)	Wuskwatim (5)	Conawapa (6)	Birthday (7)	Augmented Capacity (8)	Surplus/ Deficit (9)
1990		4503	3977	526				4503	526
1991		5143	4045	1098				5143	1098
1992		5531	4135	1396				5531	1396
1993		5205	4804	401				5205	401
1994		5213	4911	302				5213	302
1995		5559	4960	599				5559	599
1996		5796	5024	772				5796	772
1997		5816	5132	684				5816	684
1998		5830	5449	381				5830	381
1999		5838	5531	307				5838	307
2000		5843	5638	205				5843	205
2001		5847	5686	161				5847	161
2002		5850	5760	90				5850	90
2003		5853	5605	248				5853	248
2004		5857	5686	171				5857	171
2005		5729	5237	492				5729	492
2006		5733	5325	408				5733	408
2007		5737	5372	365				5737	365
2008		5741	5486	255				5741	255
2009		5745	5547	198				5745	198
2010		5749	5634	115	180			5929	295
2011		5621	5717	-96	340			5961	244
2012		5625	5799	-174	340			5965	166
2013		5629	5882	-253	340	195		6164	282
2014		5528	5965	-437	340	625		6493	528
2015	330	5532	6088	-556	340	1230		7102	1014
2016	550	5536	6197	-661	340	1230		7106	909
2017	550	5540	6280	-740	340	1230		7110	830
2018	550	5544	6363	-819	340	1230		7114	751
2019	550	5548	6446	-898	340	1230		7118	672
2020	550	5552	6528	-976	340	1230		7122	594
2021	550	5556	6611	-1055	340	1230		7126	515
2022	550	5560	6694	-1134	340	1230		7130	436
2023	550	5564	6777	-1213	340	1230		7134	357
2024	550	5568	6860	-1292	340	1230	167	7305	445
2025	550	5572	6943	-1371	340	1230	415	7557	614
2026	550	5576	7026	-1450	340	1230	540	7686	660
2027	550	5580	7109	-1529	340	1230	540	7690	581
2028	550	5584	7192	-1608	340	1230	540	7694	502

NOTES: Derived from Table 8-9.

Extended diversity refers to renewing existing and planned diversity exchanges so that diversity is not reduced within the planning period.

Extended diversity (in addition to LE-2) reduces the number of additional hydro plants required so that Manasan and First Rapids are not required in the planning period (to 2028).
The least cost sequence is Wuskwatim (2010), Conawapa (2013), Birthday (2024).

Table 8-13: MH Scenario 2 with 500 MW DSM by 2001, and with ED and LE-2 (Capacity)

Year	Add 400 MW DSM (1)	Capacity Resources (2)	Capacity Demand (3)	Surplus/ Deficit (4)	Wuskwatim (5)	Conawapa (6)	Birthday (7)	Augmented Capacity (8)	Surplus/ Deficit (9)
1990		4503	3977	526				4503	526
1991		5143	4045	1098				5143	1098
1992	16	5547	4135	1412				5547	1412
1993	32	5237	4804	433				5237	433
1994	64	5277	4911	366				5277	366
1995	128	5687	4960	727				5687	727
1996	196	5992	5024	968				5992	968
1997	276	6092	5132	960				6092	960
1998	332	6162	5449	713				6162	713
1999	364	6202	5531	671				6202	671
2000	384	6227	5638	589				6227	589
2001	400	6247	5686	561				6247	561
2002	412	6262	5760	502				6262	502
2003	424	6277	5605	672				6277	672
2004	440	6297	5686	611				6297	611
2005	456	6185	5237	948				6185	948
2006	472	6205	5325	880				6205	880
2007	488	6225	5372	853				6225	853
2008	504	6245	5486	759				6245	759
2009	520	6265	5547	718				6265	718
2010	536	6285	5634	651				6285	651
2011	552	6173	5717	456				6173	456
2012	568	6193	5799	394				6193	394
2013	584	6213	5882	331				6213	331
2014	600	6128	5965	163				6128	163
2015	616	6148	6088	60	180			6328	240
2016	632	6168	6197	-29	340			6508	311
2017	648	6188	6280	-92	340			6528	248
2018	664	6208	6363	-155	340			6548	185
2019	680	6228	6446	-218	340			6568	122
2020	696	6248	6528	-280	340		167	6755	227
2021	712	6268	6611	-343	340		415	7023	412
2022	728	6288	6694	-406	340		540	7168	474
2023	744	6308	6777	-469	340		540	7188	411
2024	760	6328	6860	-532	340		540	7208	348
2025	776	6348	6943	-595	340		540	7228	285
2026	792	6368	7026	-658	340		540	7248	222
2027	808	6388	7109	-721	340		540	7268	159
2028	824	6408	7192	-784	340		540	7288	96

NOTES: Derived from Table 8-11.

A five-fold increase in DSM (in addition to extended diversity and LE-2) reduces the number of additional hydro plants required and defers the remaining required plants.

The least cost sequence is Wuskwatim (2015) and Birthday (2020).

Conawapa, Manasan and First Rapids are not required in the planning period (to 2028).

Table 8-15: MH Scenario 2 with Thermal Replacement and 500 MW DSM, ED and LE-2 (Capacity)

Year	New Thermal (1)	Capacity Resources (2)	Capacity Demand (3)	Surplus/ Deficit (4)	Wuskwatim (5)	Conawapa (6)	Birthday (7)	Augmented Capacity (8)	Surplus/ Deficit (9)
1990		4503	3977	526				4503	526
1991		5143	4045	1098				5143	1098
1992		5547	4135	1412				5547	1412
1993		5237	4804	433				5237	433
1994		5277	4911	366				5277	366
1995		5687	4960	727				5687	727
1996		5992	5024	968				5992	968
1997		6092	5132	960				6092	960
1998		6162	5449	713				6162	713
1999		6202	5531	671				6202	671
2000		6227	5638	589				6227	589
2001		6247	5686	561				6247	561
2002		6262	5760	502				6262	502
2003		6277	5605	672				6277	672
2004		6297	5686	611				6297	611
2005		6185	5237	948				6185	948
2006		6205	5325	880				6205	880
2007		6225	5372	853				6225	853
2008		6245	5486	759				6245	759
2009		6265	5547	718				6265	718
2010		6285	5634	651				6285	651
2011	264	6437	5717	720				6437	720
2012	264	6457	5799	658				6457	658
2013	264	6477	5882	595				6477	595
2014	369	6497	5965	532				6497	532
2015	369	6517	6088	429				6517	429
2016	369	6537	6197	340				6537	340
2017	369	6557	6280	277				6557	277
2018	369	6577	6363	214				6577	214
2019	369	6597	6446	151				6597	151
2020	369	6617	6528	89				6617	89
2021	369	6637	6611	26	180			6817	206
2022	369	6657	6694	-37	340			6997	303
2023	369	6677	6777	-100	340			7017	240
2024	369	6697	6860	-163	340			7037	177
2025	369	6717	6943	-226	340			7057	114
2026	369	6737	7026	-289	340			7077	51
2027	369	6757	7109	-352	340		167	7264	155
2028	369	6777	7192	-415	340		415	7532	340

NOTES: Derived from Table 8-13.

Thermal replacement refers to replacing existing thermal plants when additional resources are required.

Replacing existing thermal capacity (in addition to increased DSM, extended diversity and LE-2) defers the remaining required plants.

The least cost sequence is Wuskwatim (2021) and Birthday (2027).

Conawapa, Manasan and First Rapids are not required in the planning period (to 2028).

Appendix XI

CAC/MSOS' Alternative Supply Scenario Sensitivity Analysis of Ontario 1000 MW Sale

(Source: Exhibit #MH-23)

CAC/MSOS Suggested

Sensitivity Analysis of Ontario 1000 MW Sale

- millions of 1990 Present Value Dollars

	Sensitivity No.	DESCRIPTION OF SENSITIVITY EXAMINED	Scenario	COST COMPONENTS Generation/ Transmission Capital Costs (Generation Exp. Costs)	Production Costs	Interconnection Capital Costs NSP/UPA 200 [illegible]	Ontario 1000 Sale	Winnipeg/ Dorsey Transmission Capital Cost	DSM Costs	Total Cost	Revenue From Firm Transactions NSP/UPA 200 [illegible]	Ontario 1000 Sale	Net Cost	Ontario Sale Benefit
NO SALE CASES	1	• 1990 Base Load Forecast ✓	2 (LA2)	1178 *	52	15		47	129	1421	51		1370	
	2	• 1990 Base Load Forecast ✓	2 (LE2)	1058 *	111	15		47	129	1360	51		1309	
	3	• 1990 Base Load Forecast ✓ • All diversity exchanges extended to the end of the study.	2 (LE2)	901 *	204	15		47	129	1296	51		1245	
	4	• 1990 Base Load Forecast • All diversity exchanges extended to the end of the study. • 267 MW Coal Plant in 2011.	2 (LE2)	754 *	370	15		47	129	1315	51		1264	
	5	• 1990 Base Load Forecast • All diversity exchanges extended to the end of the study. • 267 MW Coal Plant in 2011. • DSM targetted to be 5 times the Base Case.	2 (LE2)	331 *	176	15		47	646	1215	51		1164	
SALE CASES	7	• 1990 Base Load Forecast • All diversity exchanges extended to the end of the study. • DSM targetted to be 5 times the Base Case.	1 (LE2)	1242	111	15	63	47	646	2124	51	1602	471	693 ~~([illegible])~~ #7 VS #5
	8	• 1990 Base Load Forecast • All diversity exchanges extended to the end of the study.	1 (LE2)	1812	167	15	63	47	129	2233	51	1602	580	665 ~~([illegible])~~ #8 VS #3

NOTES:
1) Scenario "1" implies "With Ontario 1000 MW Sale"; Scenario "2" implies "Without 1000 MW Ontario Sale"
2) MOSES production costing used instead of Hydraulic Simulation Model
3) * $30 million (1990) added for reliability improvements
4) Cost of additional DSM assumed to be ~~[illegible]~~ → 2¢ / K.Wh.
5) OH sale starts in 2000

LEGEND: LA-2 = Thermal Life Assurance 2
LE-2 = Thermal Life Extension 2

8/30/90

CAC/MSOS Suggested

Sensitivity Analysis of Ontario 1000 MW Sale - millions of 1989 Present Value Dollars

Sensitivity No.	DESCRIPTION OF SENSITIVITY EXAMINED	Scenario	SEQUENCE
1	- 1990 Base Load Forecast	2 (LA2)	W-06, M-11, C-14, B-20, FR-27
2	- 1990 Base Load Forecast	2 (LE2)	W-10, C-13, B-17, M-23, FR-27
3	- 1990 Base Load Forecast - All diversity exchanges extended to the end of the study.	2 (LE2)	W-10, C-13, B-25
4	- 1990 Base Load Forecast - All diversity exchanges extended to the end of the study. - 267 MW Coal Plant in 2011.	2 (LE2)	CL1-11, W-13, B-16, C-23
5	- 1990 Base Load Forecast - All diversity exchanges extended to the end of the study. - 267 MW Coal Plant in 2011. - DSM targetted to be 5 times the Base Case.	2 (LE2)	CL1-11, W-21, M-27
[illegible] 7	- 1990 Base Load Forecast - All diversity exchanges extended to the end of the study. - DSM targetted to be 5 times the Base Case.	1 (LE2)	C-02
~~4~~ 8	- 1990 Base Load Forecast - All diversity exchanges extended to the end of the study.	1 (LE2)	C-00, W-10, B-14

NOTES: 1) Scenario "1" implies "With Ontario 1000 MW Sale"; Scenario "2" implies "Without 1000 MW Ontario Sale"
2) MOSES production costing used instead of Hydraulic Simulation Model.

LEGEND: LA-2 = Thermal Life Assurance 2
LE-2 = Thermal Life Extension 2

8/30/90

Appendix XII
MIPUG's Graphic Review: Supply-Demand Balances
(Source: Exhibit #MIPUG-9)

GRAPHIC REVIEW: SUPPLY-DEMAND BALANCES (VARIOUS CASES)

Graphs are provided to summarize supply and demand (MW and GWh) development planning balances for the period 1990 to 2028 under various cases.

GRAPH 1 - BASE CASE: existing plant and export levels are reviewed in the context of the 1990 Load Forecast and present DSM targets; this graph indicates the situation as projected by Manitoba Hydro without any modification other than LA-1 (thermal) and the present DSM target

GRAPH 2: contrasts Base Case with addition of Conawapa/Bipole III and Ontario Sale (no other change)

GRAPH 3: contrasts Base Case with NSP/UPA diversity exchange agreement case (no new plant)

GRAPH 4: contrasts Base Case with NSP/UPA diversity plus Ontario Sale and Conawapa/Bipole III

GRAPHS 5 and 6: same as Graph 4, except assumes greater DSM (at 2x and 5x the target)

GRAPH 7: contrasts Base Case with NSP/UPA and Diversity Extended beyond 2028 (no new plant)

GRAPH 8: contrasts Base Case with NSP/UPA, Diversity Extended, and LE-2 (no new plant)

GRAPHS 9 and 10: same as Graph 8, except assumes greater DSM (at 2x and 5x the target)

GRAPH 11: contrasts Base Case with same elements as Graph 8 plus Conawapa/Bipole III and Ontario Sale

GRAPHS 12 and 13: same as Graph 11, except assumes greater DSM (at 2x and 5x the target)

Table 1 summarizes projected MW and GWh shortfall dates indicated in each graph (case) up to the year 2028. Additional supply and/or reduced loads may be required prior to such "shortfall dates" in order to ensure adequate system reliability. Commitments regarding new capital development programs would, of course, normally be required many years prior to the "shortfall dates" indicated in these graphs if supply shortfalls are to be avoided.

Graphs 14 and 15 present similar information for the full Sequence 1 and Sequence 2 as defined by Manitoba Hydro, including development of sufficient new plants to ensure that no shortfalls occur during the planning period.

Attachment A presents Technical Notes, including definitions of various terms, data sources, and actual data utilized for the graphs.

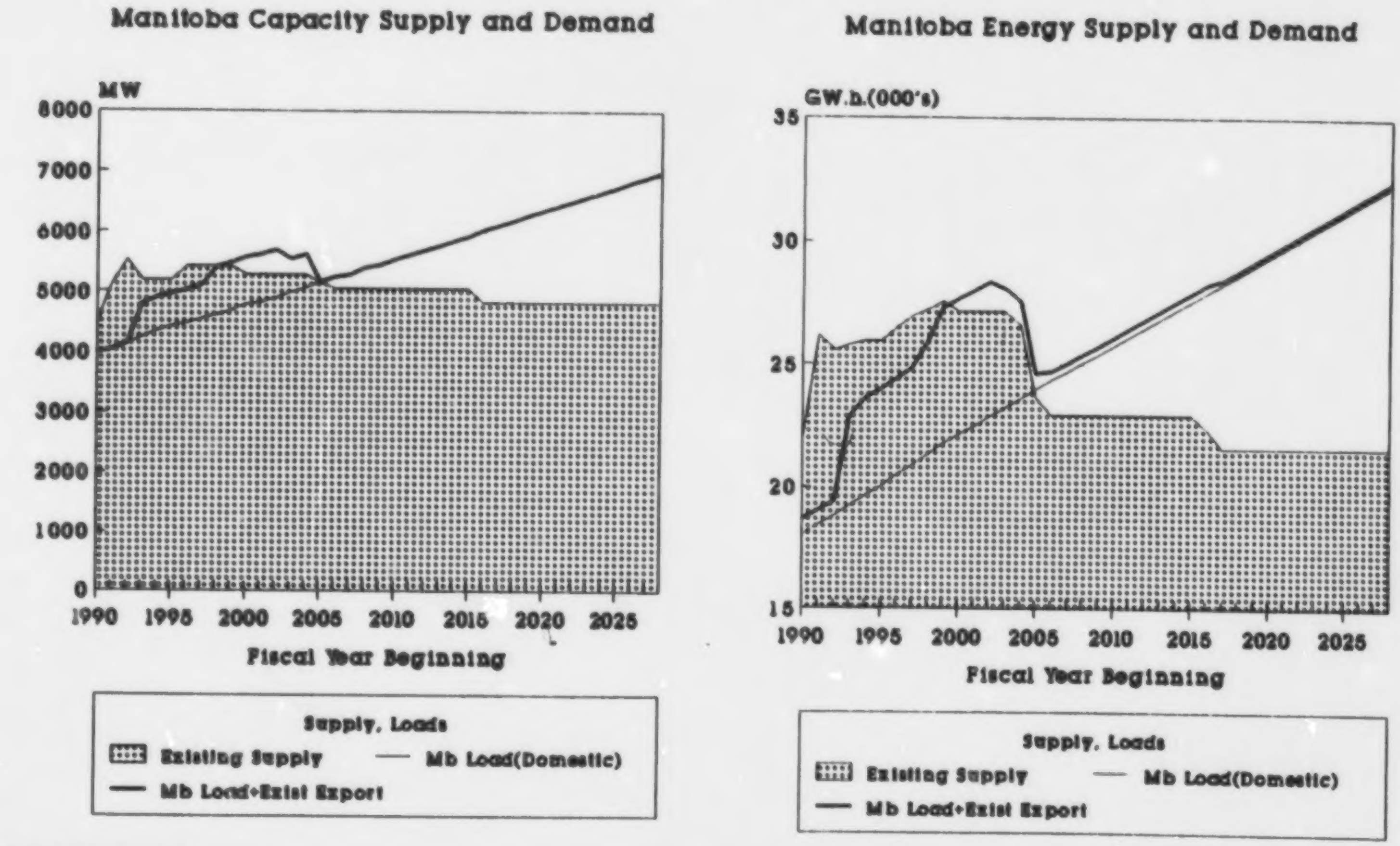
TABLE 1

PROJECTED MW AND GWh SHORTFALL PERIODS TO 2028

	MW	GWh
LA-1		
Graph 1: Existing Plant	1999 and beyond	2000 and beyond
Graph 2: Conawapa/Ontario Sale	1999-2004 2006 and beyond	2004 and beyond
LA-1, NSP/UPA		
Graph 3: Existing Plant	2002 (42 MW) 2009 and beyond	2006 and beyond
Graph 4: Conawapa/Ontario Sale	2011 and beyond	2008 and beyond
Graph 5: with 2x DSM	2012 and beyond	2010 and beyond
Graph 6: with 5x DSM	2015-2021 2027 and beyond	2015 and beyond
LA-1, NSP/UPA, Diversity Extended		
Graph 7: Existing Plant	2009 and beyond	2006 and beyond
LE-2, NSP/UPA, Diversity Extended		
Graph 8: Existing Plant	2011 and beyond	2011 and beyond
Graph 9: with 2x DSM	2012 and beyond	2011 and beyond
Graph 10: with 5x DSM	2017 and beyond	2015 and beyond
Graph 11: Conawapa/Ontario Sale	2012-2021 2025 and beyond	2011 and beyond
Graph 12: with 2x DSM	2014-2021 2027 and beyond	2012 and beyond
Graph 13: with 5x DSM	no shortfall	2017-2018 only

GRAPH 1

LA-1, Existing Plant, 1990 Forecast, DSM



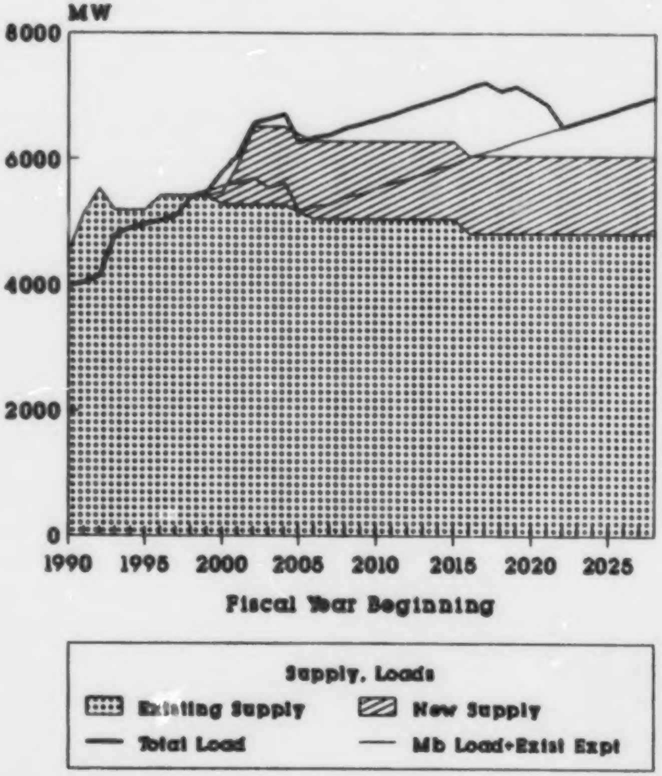
*Supply, load minus DSM
*Manitoba Load includes Reserve
Source: CAC/MSOS (I) 1.4 Table 7.9a

*Supply, load minus DSM
Source: CAC/MSOS (I) 1.4 Table 7.10

GRAPH 2

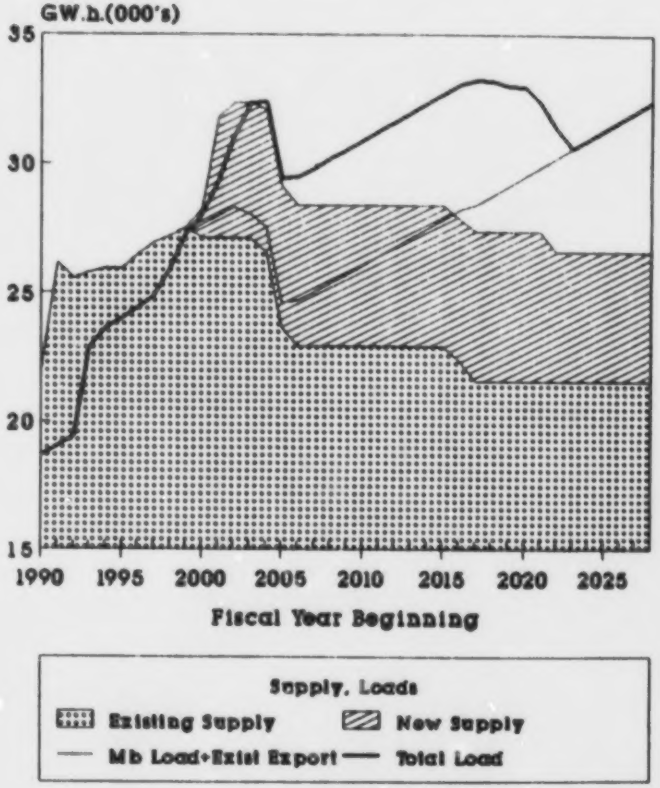
LA-1, Existing Plant, DSM, Conawapa, OntSale

Manitoba Capacity Supply and Demand



*Supply, load minus DSM
*Manitoba Load includes Reserve
Source: CAC/MSOS (I) 1.6 Table 7.9a,7-1a

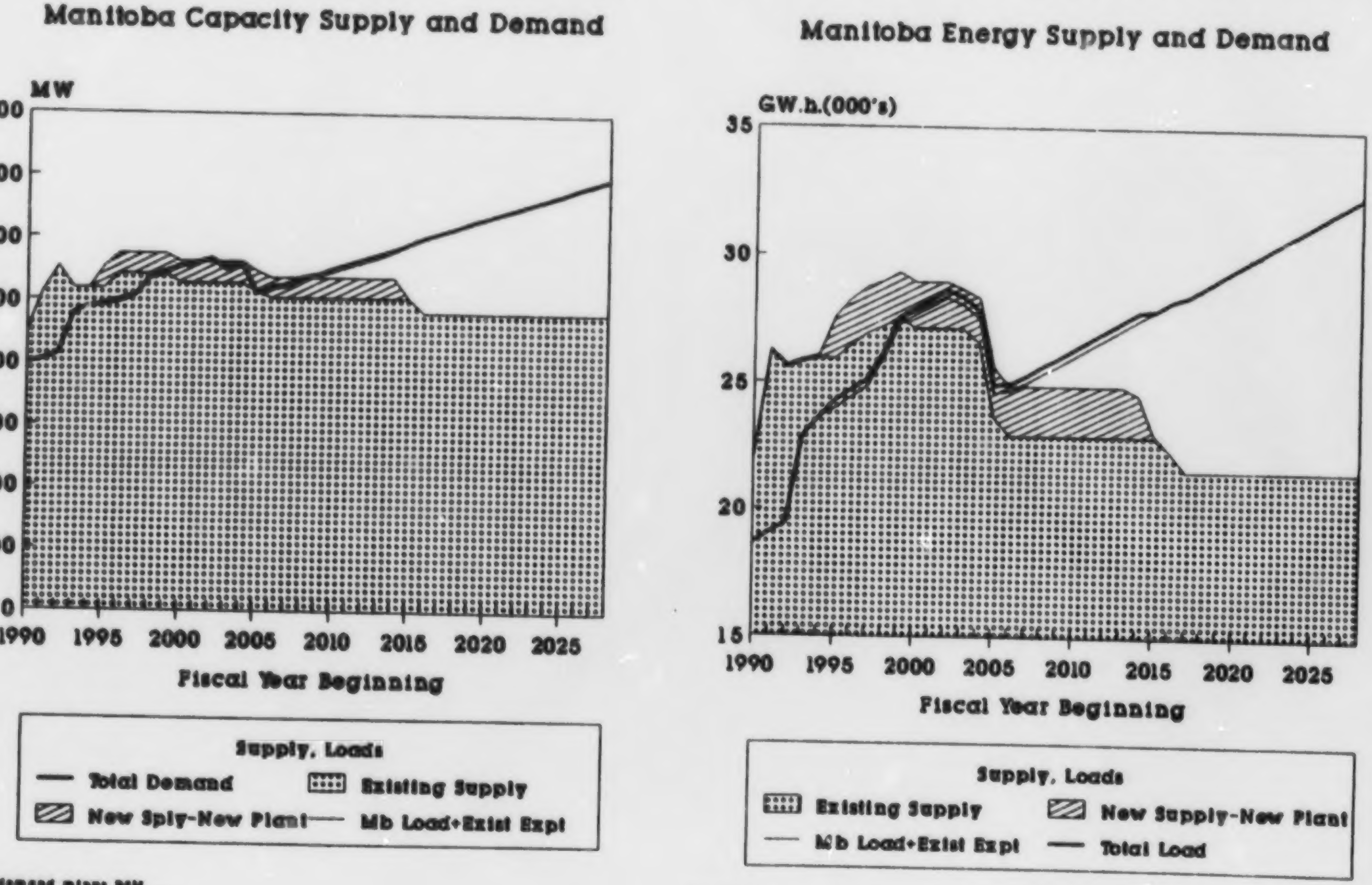
Manitoba Energy Supply and Demand



*Supply, load minus DSM
Source: CAC/MSOS (I) 1.4 Table 7.10,7-3a

GRAPH 3

LA-1, NSP/UPA, Existing Plant, 1990 Load Forecast, DSM



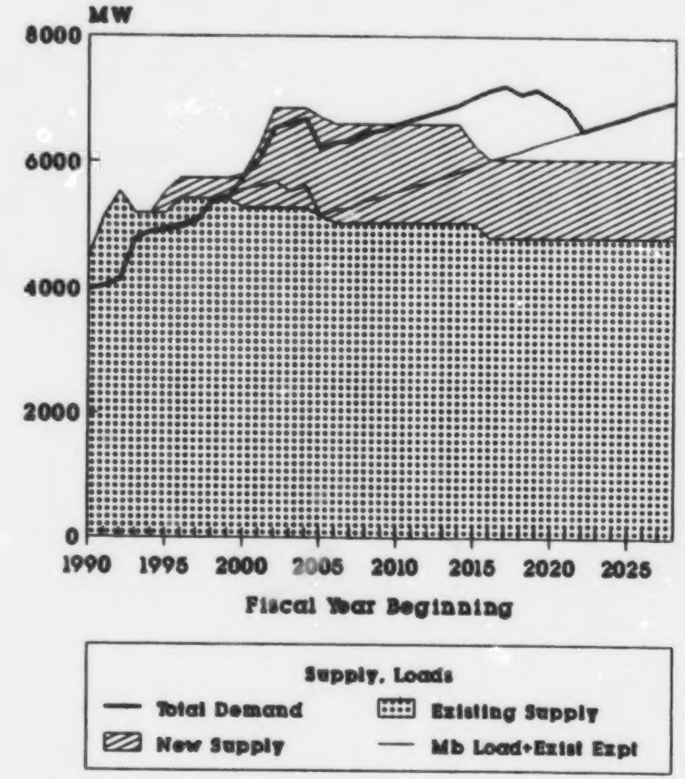
*Supply, demand minus DSM
*Manitoba Load includes Reserve
Source: CAC/MSOS (I) 1.4 Table 7.5c

*Supply, load minus DSM
Source: CAC/MSOS (I) 1.4 Table 7.6a

GRAPH 4

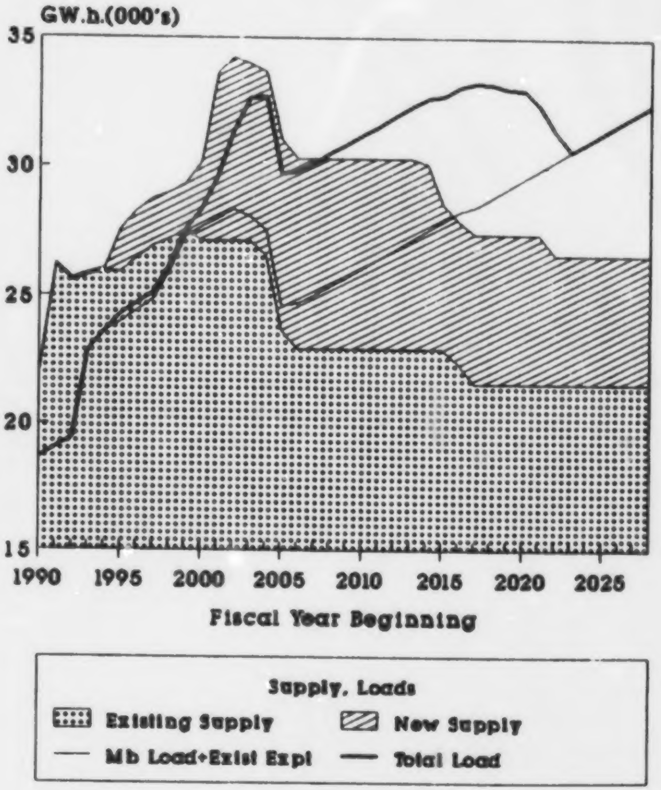
LA-1, NSP/UPA, Existing Plant, DSM, Conwpa, OntSale

Manitoba Capacity Supply and Demand



*Supply, demand minus DSM
*Manitoba Load includes Reserve
Source: CAC/MSOS (I) 1.4 Table 7.6a

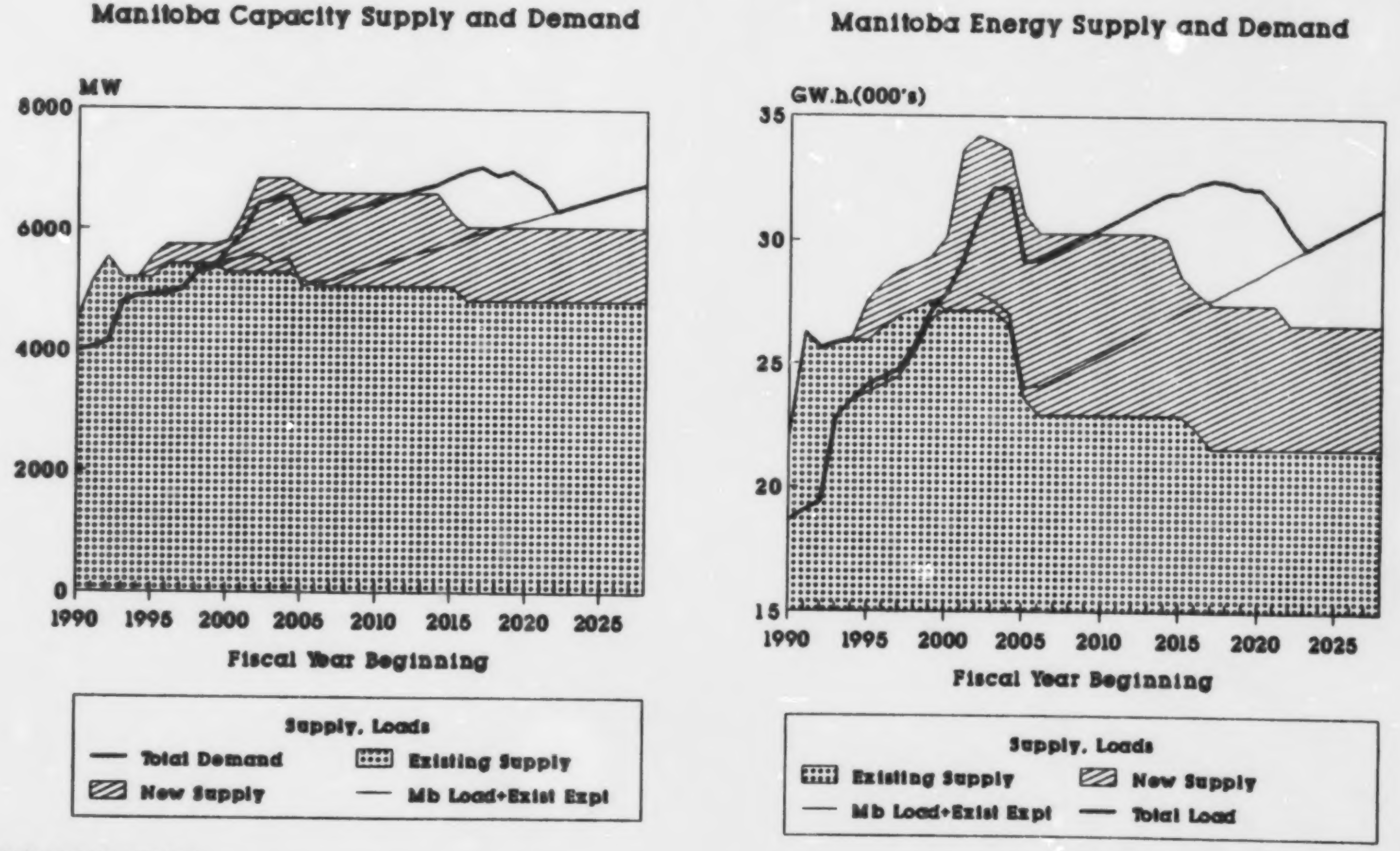
Manitoba Energy Supply and Demand



*Supply, load minus DSM
Source: CAC/MSOS (I) 1.4 Table 7.6a

GRAPH 5

LA-1, NSP/UPA, Existing Plant, DSMx2, Conwpa, OntSale



Manitoba Capacity Supply and Demand

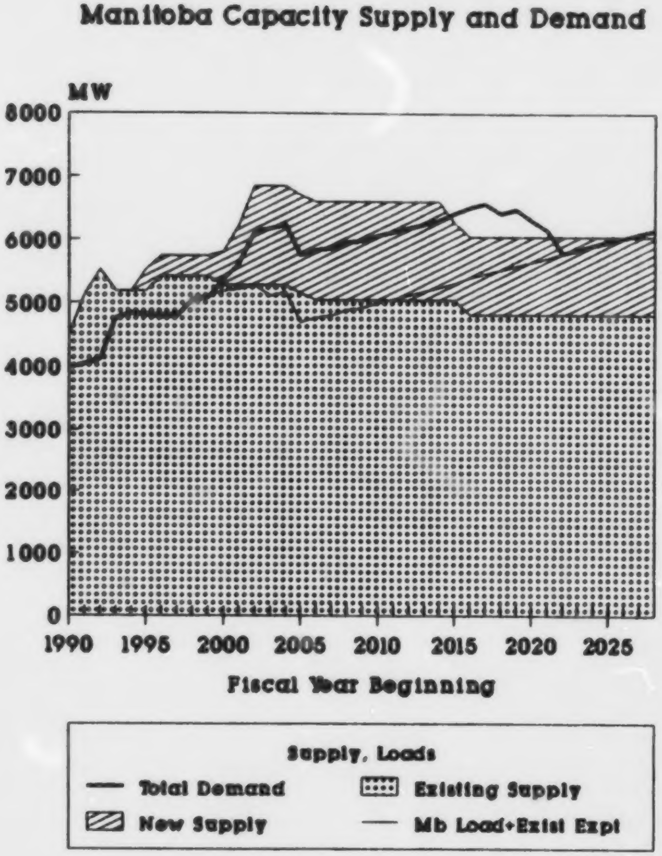
Manitoba Energy Supply and Demand

*Supply, demand minus DSM
*Manitoba Load includes Reserve
Source: CAC/MSOS (I) 1.4 Table 7.6a

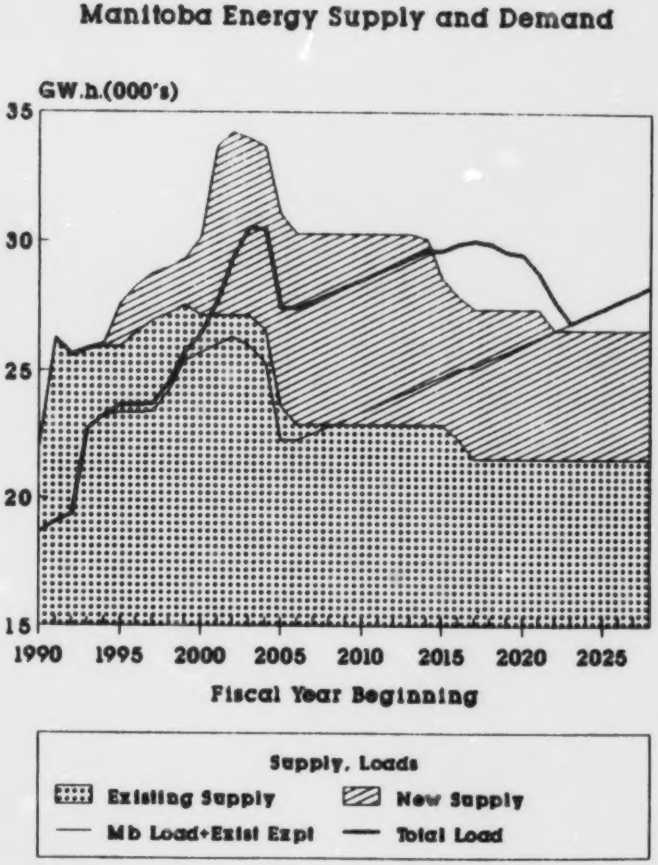
*Supply, load minus DSM
Source: CAC/MSOS (I) 1.4 Table 7.6a

GRAPH 6

LA-1, NSP/UPA, Existing Plant, DSMx5, Conwpa, OntSale


Manitoba Capacity Supply and Demand

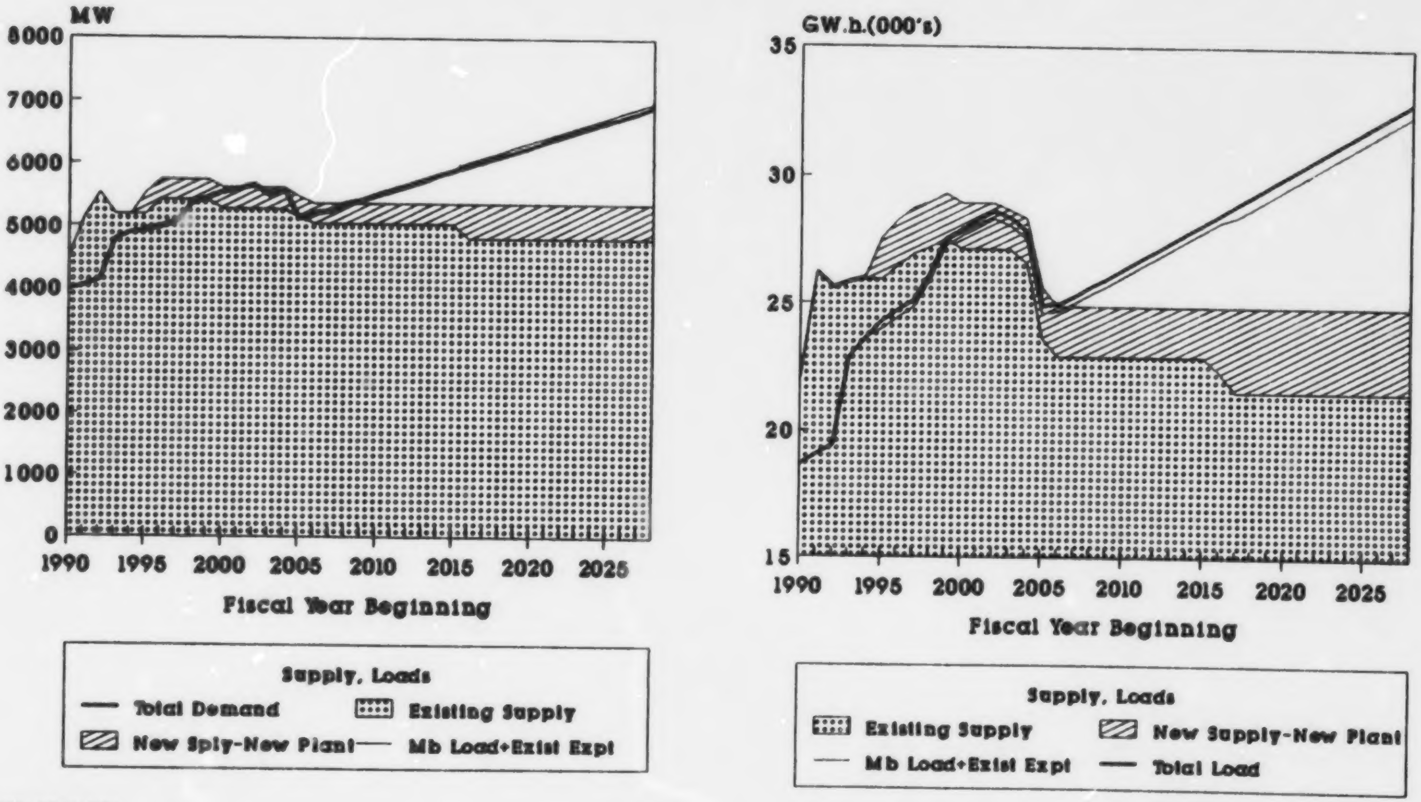
*Supply, demand minus DSM
*Manitoba Load includes Reserve
Source: CAC/MSOS (I) 1.4 Table 7.6a


Manitoba Energy Supply and Demand

*Supply, load minus DSM
Source: CAC/MSOS (I) 1.4 Table 7.6a

GRAPH 7

LA-1, NSP/UPA, Existing Plant, DSM, Diversity Extended

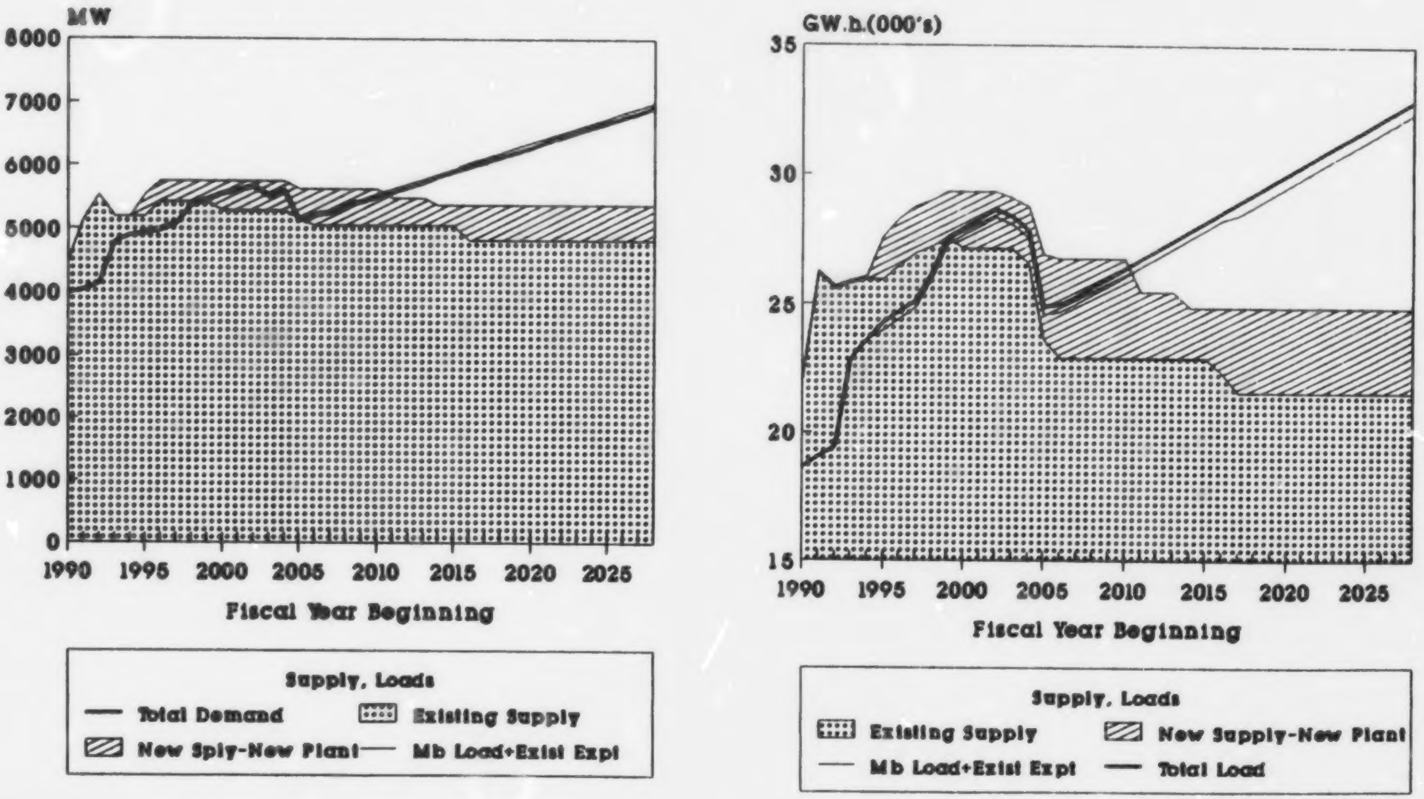


*Supply minus DSM
*Manitoba Load includes Reserve
Source: CAC/MSOS (I) 1.4 Table 7.6a

*Supply, load minus DSM
Source: CAC/MSOS (I) 1.4 Table 7.6a

GRAPH 8

NSP/UPA, Existing Plant, DSM, Div. Extended, LE-2



Manitoba Capacity Supply and Demand

Manitoba Energy Supply and Demand

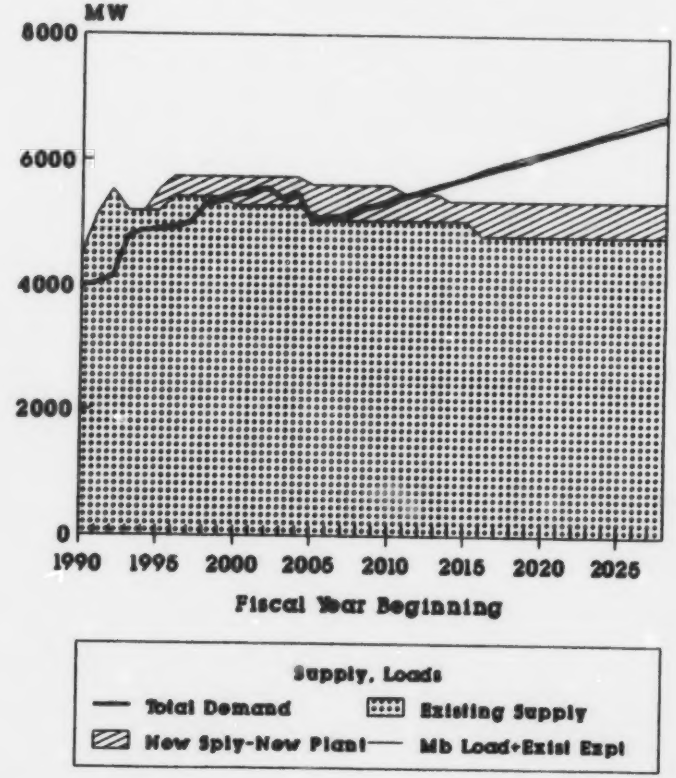
*Supply minus DSM
*Manitoba Load includes Reserve
Source: CAC/MSOS (I) 1.4 Tables7.[illegible]

*Supply, load minus DSM
Source: CAC/MSOS (I) 1.4 Tables7.[illegible]

GRAPH 9

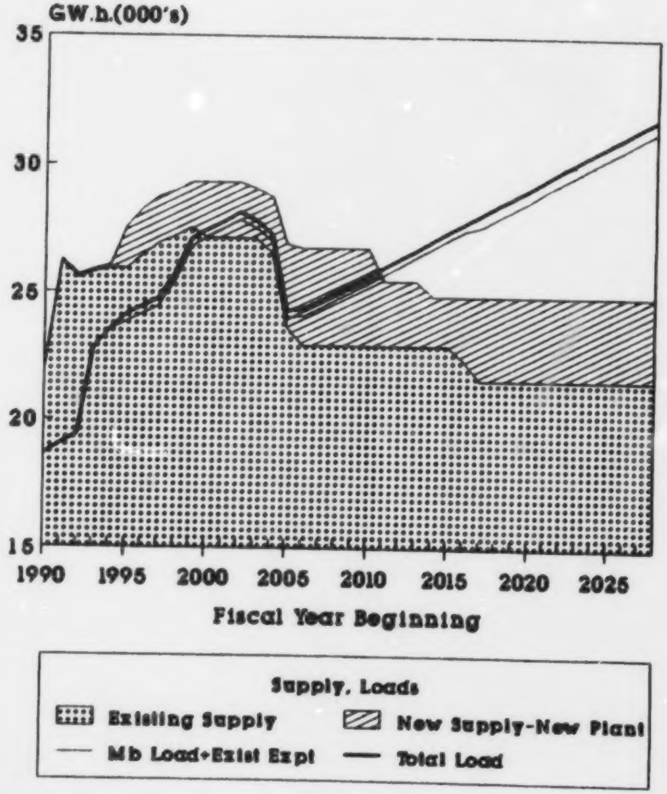
NSP/UPA, Existing Plant, DSMx2, Div. Extended, LE-2

Manitoba Capacity Supply and Demand



*Supply minus DSM
*Manitoba Load includes Reserve
Source: CAC/MSOS (I) 1.4 Tables7.6abc

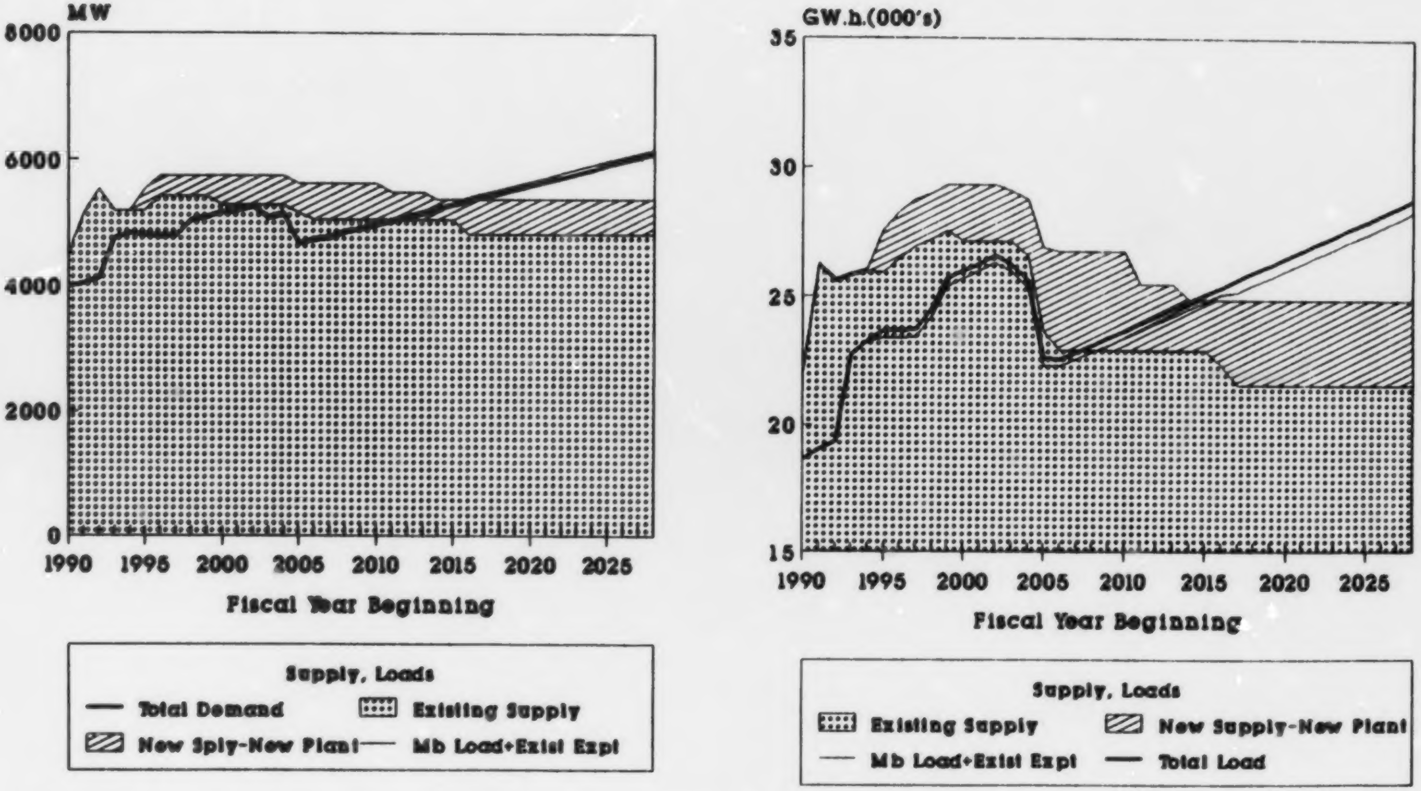
Manitoba Energy Supply and Demand



*Supply, load minus DSM
Source: CAC/MSOS (I) 1.4 Tables7.6abc

GRAPH 10

NSP/UPA, Existing Plant, DSMx5, Div. Extended, LE-2



Manitoba Capacity Supply and Demand

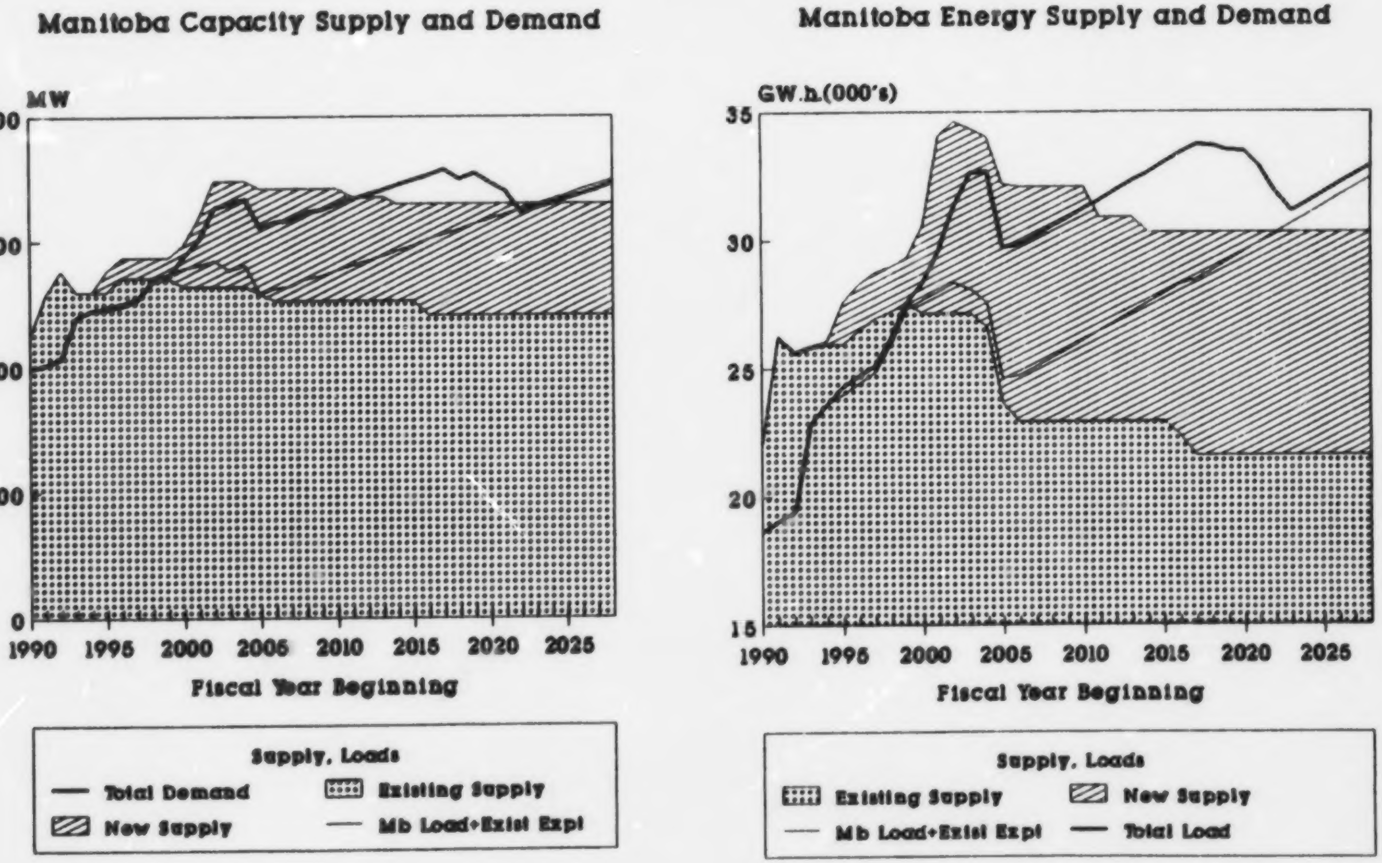
Manitoba Energy Supply and Demand

*Supply minus DSM
*Manitoba Load Includes Reserve
Source: CAC/MH08 (I) 1.4 Tables7.6abc

*Supply, load minus DSM
Source: CAC/MH08 (I) 1.4 Tables7.6abc

GRAPH 11

NSP/UPA, Ex.Plant+Conwpa, DSM, LE-2, Div.Ext.,OntSale



Manitoba Capacity Supply and Demand

Manitoba Energy Supply and Demand

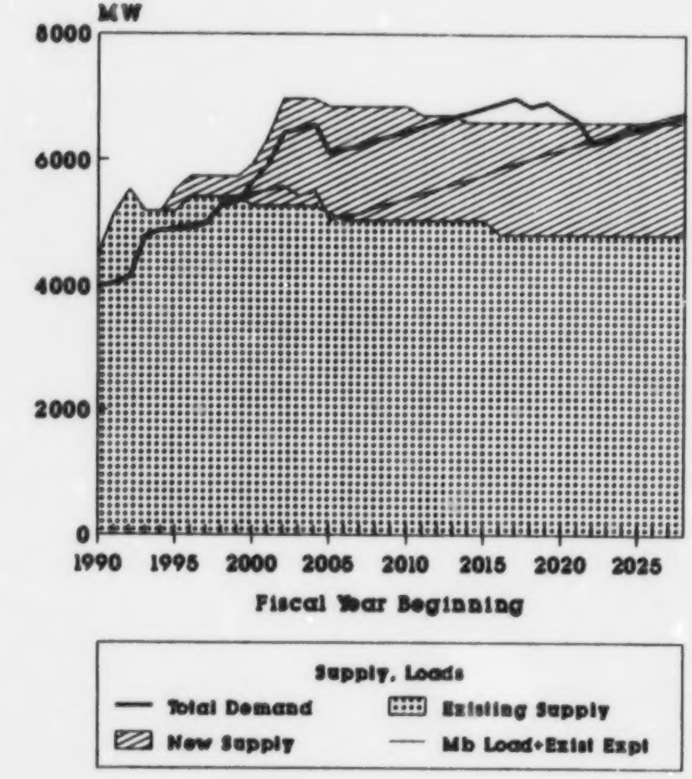
*Supply minus DSM
*Manitoba Load includes Reserve
Source: CAC/MSOS (I) 1.4 Tables7.[illegible]

*Supply, load minus DSM
Source: CAC/MSOS (I) 1.4 Tables7.[illegible]

GRAPH 12

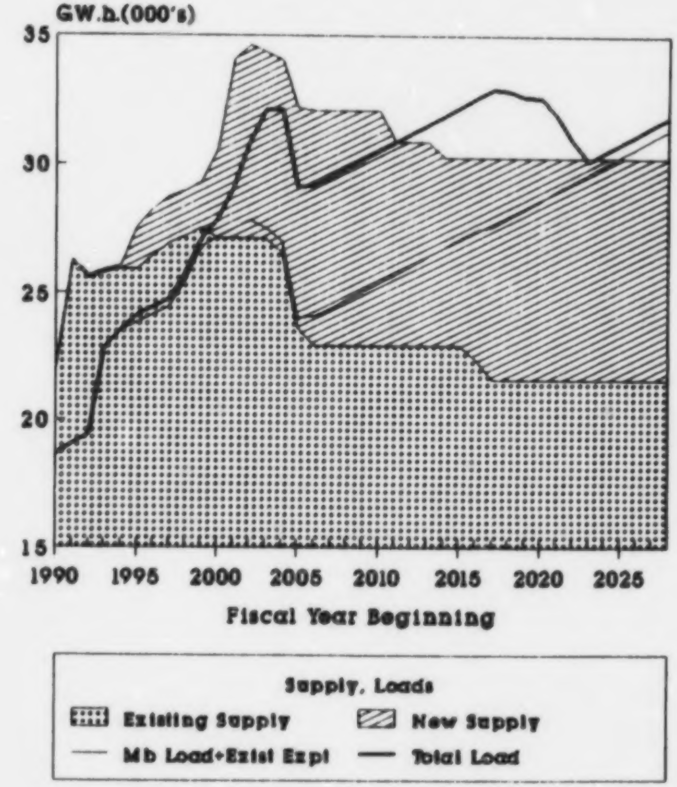
NSP/UPA, Ex.Plant+Conwpa, DSMx2, LE-2, Div.Ext,OntSale

Manitoba Capacity Supply and Demand



*Supply minus DSM
*Manitoba Load includes Reserve
Source: CAC/MH08 (I) 1.4 Tables7.sabe

Manitoba Energy Supply and Demand

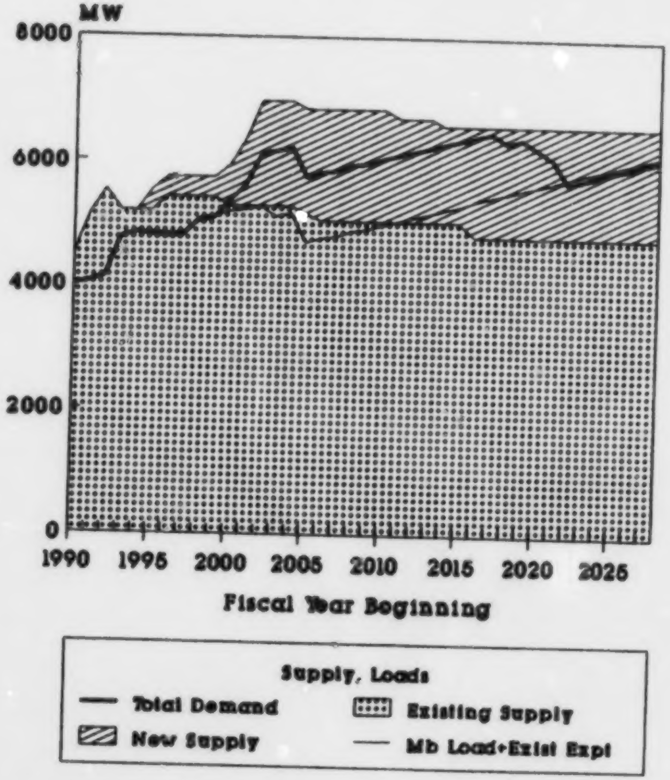


*Supply, load minus DSM
Source: CAC/MH08 (I) 1.4 Tables7.sabe

GRAPH 13

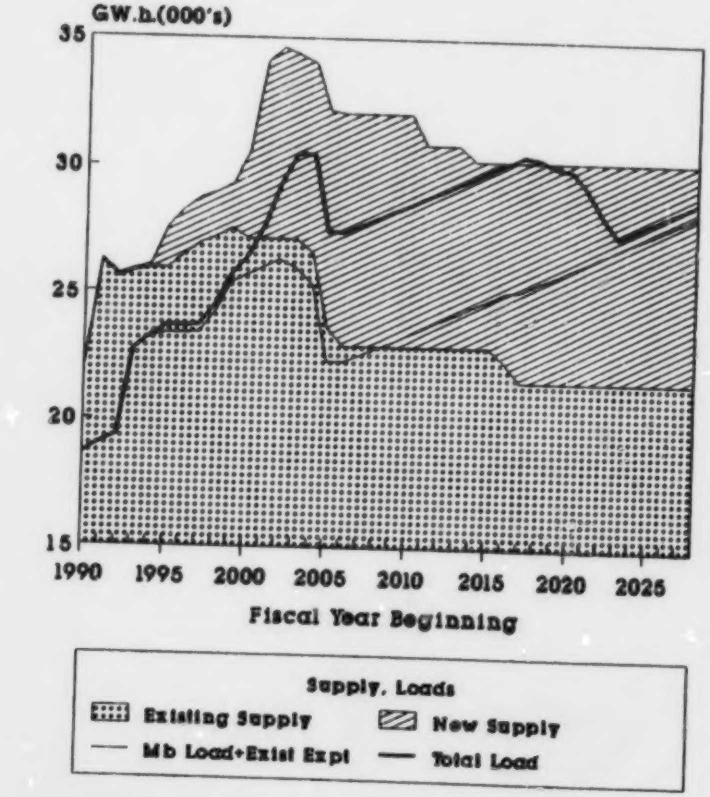
NSP/UPA, Ex.Plant+Conwpa, DSMx5, LE-2, Div.Ext,OntSale

Manitoba Capacity Supply and Demand



*Supply minus DSM
*Manitoba Load includes Reserve
Source: CAC/MSOS (I) 1.4 Tables7.[illegible]

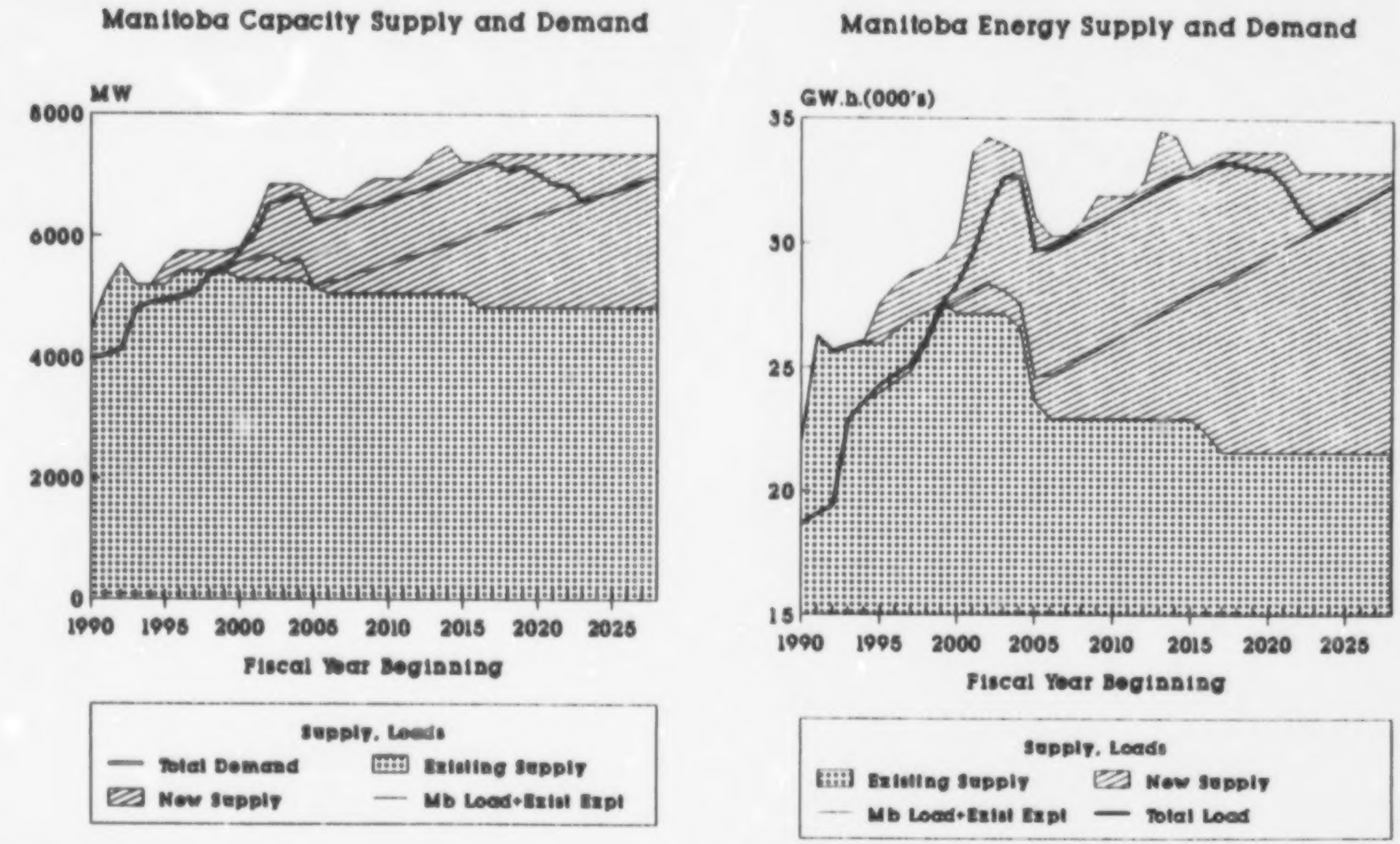
Manitoba Energy Supply and Demand



*Supply, load minus DSM
Source: CAC/MSOS (I) 1.4 Tables7.[illegible]

GRAPH 14

Sequence 1, 1990 Load Forecast



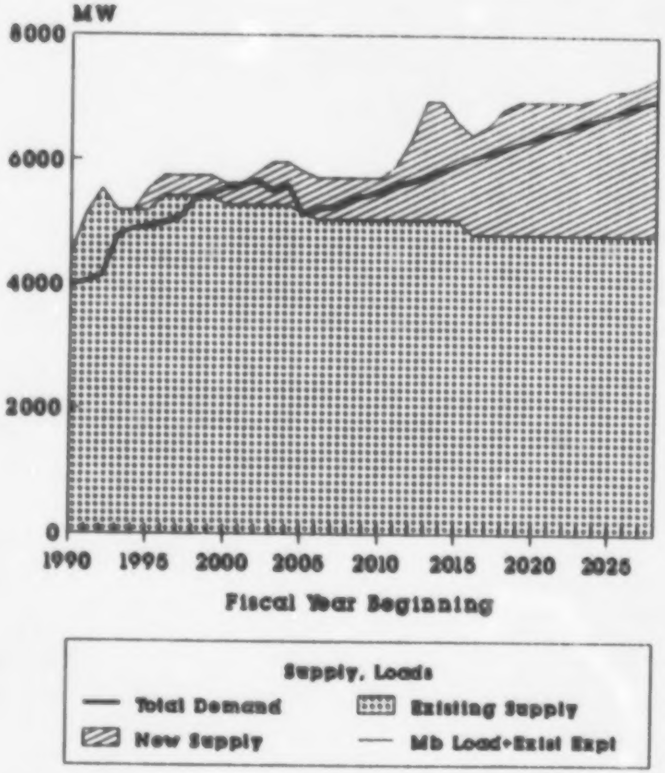
*Supply, demand minus DSM
*Manitoba Load includes Reserve
Source: CAC/MSOS (I) 1.4 Table 7.1a

*Supply, load minus DSM
Source: CAC/MSOS (I) 1.4 Table 7.2a

GRAPH 15

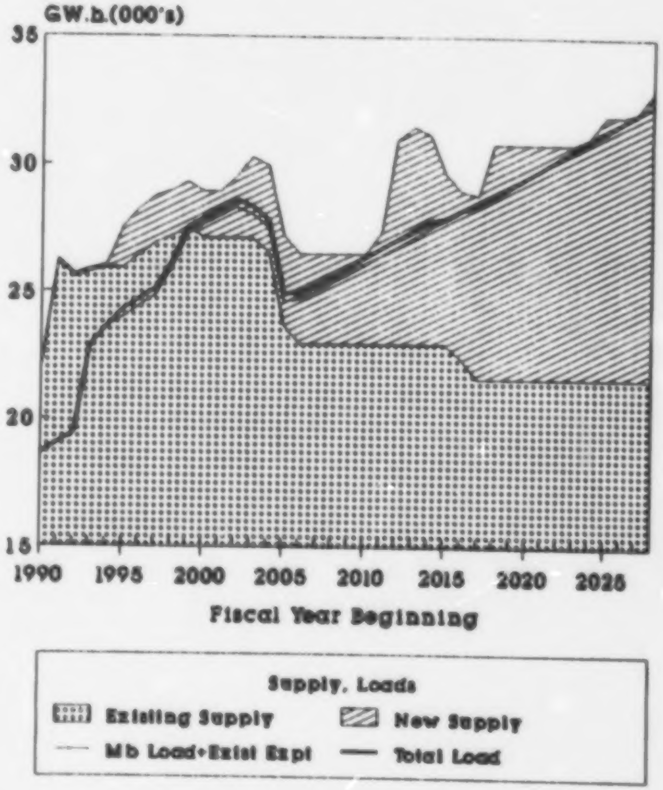
Sequence 2, 1990 Load Forecast

Manitoba Capacity Supply and Demand



*Supply, demand minus DSM
*Manitoba Load includes Reserve
Source: CAC/MSOS (I) 1.4 Table 7.5a

Manitoba Energy Supply and Demand



*Supply, load minus DSM
Source: CAC/MSOS (I) 1.4 Table 7.4a

ATTACHMENT A

GRAPHIC REVIEW OF SUPPLY-DEMAND BALANCES: TECHNICAL NOTES

The graphic review of Manitoba Hydro development planning supply-demand balances (MW and GWh) from 1990 to 2028 for various cases focuses throughout on four items:

a. **Existing Supply (same for all cases):** the capability of existing plant (MW and GWh), assuming LA-1 (thermal assurance as per Manitoba Hydro's Preferred Development Plan) and existing hydraulic generation (GWh) based on LA-1 and existing export contracts (prior to NSP/UPA and new Ontario Sale). Energy reflects dependable energy as per Manitoba Hydro's testimony.

b. **Manitoba Load + Existing Export (same for most cases):** 1990 Load Forecast (MW and GWh) **minus** DSM as per Manitoba Hydro's Preferred Development Plan, **plus** existing exports (prior to NSP/UPA and new Ontario Sale) to the extent exports affect planning capacity for energy demand, and **plus** (in the case of capacity) the Reserve margin calculated as per Manitoba Hydro's testimony. Some cases examine modified DSM options (2 and 5 times Manitoba Hydro's present targets).

c. **New Supply OR New Supply - New Plant (varies by case):** the additional supply (MW and GWh) associated with the case:
   - includes adjustment to existing plant dependable energy where relevant (thermal or export adjustments cases)
   - includes new or modified plant only as specified

d. **Total Demand or Total Load (varies by case):** the total demand (MW) or load (GWh) associated with the case:
   - includes impact of any new exports specified
   - includes adjustment to Reserves (MW) where relevant (new firm demand import capability)
   - includes adjustment to DSM where specified (see above).

The **source** for all data is Manitoba Hydro's response to CAC/MSOS/MH (1) 1.4, 2.2 and 2.5, except as otherwise noted below:

a. **Existing Supply:** based on Tables 7-9a and 7-10a (Sequence 4), excluding new plant (reflects existing plant hydraulic capability without new exports, assuming thermal LA-1)

b. **Manitoba Load + Existing Export:** based on Tables 7-9a and 7-10a (Sequence 4); reflects situation without new exports and with present DSM targets

c. **New Supply:**

   i. **Conawapa:** as per Tables 7.1a and 7.2a (Sequence 1) including adjustment to existing hydraulic energy

   ii. **NSP/UPA:** as per Tables 7.5a and 7.6a (Sequence 2) diversity adjustments relative to Sequence 4, plus adjustment to existing hydraulic energy

   iii. **Diversity Extended:** as per Table 7b for diversity; existing hydro plant energy decline shown for Year 2014 is delayed beyond Year 2028, assuming 22,022 GWh/year in cases without Conawapa (in Conawapa cases, 22,600 GWh/year continues through Year 2021, with 22,200 GWh/year thereafter)

   iv. **LE-2:** as per Table 7c for thermal; existing hydro plant energy decline previously shown for Year 2005 is delayed until Year 2010 (Sequence 1 used for cases with Conawapa, Sequence 2 used for cases without Conawapa)

   v. **Sequence 1:** as per Tables 7.1a and 7.2a

   vi. **Sequence 2:** as per Tables 7.5a and 7.6a

d. **Total Demand or Total Load:**
   - modifications introduced as relevant to reflect NSP/UPA (Tables 7.5a and 7.6a), Ontario Sale (Tables 7.1a and 7.2a), Diversity Extension (Table 7b)
   - DSM modifications as specified.

Actual data used in the graphs are presented in the following attached tables:

- **Table A1: LA-1, Existing Plant, DSM**
  - Existing Supply (MW and GWh)
  - Manitoba Load + Existing Export (MW and GWh)

- **Table A2: LA-1, Existing Plant, DSM, Conawapa, Ontario Sale**
  - New Supply with Conawapa (MW and GWh)
  - Total Load with Ontario Sale (MW and GWh)
- **Table A3: LA-1, NSP/UPA, Existing Plant, DSM**
  - New Supply (MW and GWh)
  - Total Load (MW and GWh)
- **Table A4: LA-1, NSP/UPA, Existing Plant + Conawapa, DSM, Ontario Sale**
  - New Supply (MW and GWh)
  - Total Load (MW and GWh)
- **Table A5: Table A4 with DSM Variations**
  - Total Load with DSM x 2 (MW and GWh)
  - Total Load with DSM x 5 (MW and GWh)
- **Table A6: LA-1, NSP/UPA, Existing Plant, DSM, Diversity Extended**
  - New Supply (MW and GWh)
  - Total Load (MW and GWh)
- **Table A7: NSP/UPA, Existing Plant, DSM, Diversity Extended, LE-2**
  - New Supply (MW and GWh)
  - Total Load (MW and GWh)
- **Table A8: Table A7 with DSM Variations**
  - Total Load with DSM x 2 (MW and GWh)
  - Total Load with DSM x 5 (MW and GWh)
- **Table A9: NSP/UPA, Existing Plant + Conawapa, DSM, LE-2, Diversity Extended, Ontario Sale**
  - New Supply (MW and GWh)
  - Total Load (MW and GWh)
- **Table A10: Table A9 with DSM Variations**
  - Total Load with DSM x 2 (MW and GWh)
  - Total Load with DSM x 5 (MW and GWh)

TABLE A1: LA-1, EXISTING PLANT, DSM

	Existing Supply		Manitoba Load + Existing Export	
X Data	MW	GWh	MW	GWh
1990	4503	21987	3977	18670
1991	5143	26172	4046	19072
1992	5527	25571	4131	19447
1993	5197	25809	4796	22880
1994	5197	25940	4895	23623
1995	5197	25940	4968	23991
1996	5417	26481	5015	24415
1997	5417	26971	5103	24839
1998	5417	27212	5406	25930
1999	5417	27549	5479	27278
2000	5285	27149	5582	27652
2001	5285	27149	5626	28000
2002	5285	27149	5697	28357
2003	5285	27149	5538	28086
2004	5285	26571	5616	27561
2005	5153	23662	5163	24628
2006	5048	22931	5246	24698
2007	5048	22931	5289	25035
2008	5048	22931	5399	25382
2009	5048	22931	5457	25735
2010	5048	22931	5539	26098
2011	5048	22931	5618	26460
2012	5048	22931	5697	26822
2013	5048	22931	5776	27184
2014	5048	22931	5855	27546
2015	5048	22931	5934	27908
2016	4828	22390	6039	28270
2017	4828	21600	6118	28438
2018	4828	21600	6197	28800
2019	4828	21600	6276	29162
2020	4828	21600	6354	29524
2021	4828	21600	6433	29886
2022	4828	21600	6512	30248
2023	4828	21600	6591	30610
2024	4828	21600	6670	30972
2025	4828	21600	6749	31334
2026	4828	21600	6828	31696
2027	4828	21600	6907	32058
2028	4828	21600	6986	32420

TABLE A2: LA-1, EXISTING PLANT, DSM, CONAWAPA, ONTARIO SALE

	New Supply		Total Load	
X Data	MW	GWh	MW	GWh
1990	0	0	3977	18670
1991	0	0	4046	19072
1992	0	0	4131	19447
1993	0	0	4796	22880
1994	0	0	4895	23623
1995	0	0	4968	23991
1996	0	0	5015	24415
1997	0	0	5103	24839
1998	0	0	5406	25930
1999	0	0	5479	27278
2000	195	1110	5802	28054
2001	625	4650	6066	29366
2002	1230	5200	6577	31089
2003	1230	5200	6638	32345
2004	1230	5500	6716	32382
2005	1230	5500	6263	29449
2006	1230	5500	6346	29519
2007	1230	5500	6389	29856
2008	1230	5500	6499	30203
2009	1230	5500	6557	30556
2010	1230	5500	6639	30919
2011	1230	5500	6718	31281
2012	1230	5500	6797	31643
2013	1230	5500	6876	32005
2014	1230	5500	6955	32367
2015	1230	5500	7034	32729
2016	1230	5500	7139	33091
2017	1230	5800	7218	33259
2018	1230	5800	7077	33220
2019	1230	5800	7156	33019
2020	1230	5800	7014	32979
2021	1230	5800	6873	32377
2022	1230	5000	6512	31373
2023	1230	5000	6591	30610
2024	1230	5000	6670	30972
2025	1230	5000	6749	31334
2026	1230	5000	6828	31696
2027	1230	5000	6907	32058
2028	1230	5000	6986	32420

TABLE A3: LA-1, MSP/UPA, EXISTING PLANT, DSM

	New Supply - New Plant		Total Demand/Load	
X Data	MW	GWh	MW	GWh
1990	0	100	3977	18634
1991	0	100	4045	19072
1992	0	100	4131	19447
1993	0	100	4796	22880
1994	0	100	4895	23623
1995	330	1657	4928	24282
1996	330	1773	4975	24706
1997	330	1773	5063	25130
1998	330	1773	5366	26221
1999	330	1773	5440	27569
2000	330	1773	5542	27943
2001	330	1773	5586	28291
2002	330	1773	5657	28648
2003	330	1532	5499	28377
2004	330	1773	5576	27852
2005	330	1973	5123	24919
2006	330	1973	5207	24989
2007	330	1973	5250	25326
2008	330	1973	5360	25673
2009	330	1973	5417	26026
2010	330	1973	5500	26389
2011	330	1973	5579	26751
2012	330	1973	5657	27113
2013	330	1973	5736	27475
2014	330	1673	5815	27837
2015	0	116	5934	27908
2016	0	0	6039	28270
2017	0	0	6118	28438
2018	0	0	6197	28800
2019	0	0	6276	29162
2020	0	0	6354	29524
2021	0	0	6433	29886
2022	0	0	6512	30248
2023	0	0	6591	30610
2024	0	0	6670	30972
2025	0	0	6749	31334
2026	0	0	6828	31696
2027	0	0	6907	32058
2028	0	0	6986	32420

TABLE A4: LA-1, NSP/UPA, EXISTING PLANT + CONAWAPA, DSM, ONTARIO SALE

	New Supply		Total Demand/Load	
X Data	MW	GWh	MW	GWh
1990	0	100	3977	18634
1991	0	100	4045	19072
1992	0	100	4131	19447
1993	0	100	4796	22880
1994	0	100	4895	23623
1995	330	1657	4928	24282
1996	330	1773	4975	24706
1997	330	1773	5063	25130
1998	330	1773	5366	26221
1999	330	1773	5440	27569
2000	525	2983	5762	28345
2001	955	6523	6026	29657
2002	1560	7073	6537	31380
2003	1560	6832	6599	32636
2004	1560	7073	6676	32673
2005	1560	7373	6223	29740
2006	1560	7373	6307	29810
2007	1560	7373	6350	30147
2008	1560	7373	6460	30494
2009	1560	7373	6517	30847
2010	1560	7373	6600	31210
2011	1560	7373	6679	31572
2012	1560	7373	6757	31934
2013	1560	7373	6836	32296
2014	1560	7173	6915	32658
2015	1230	5616	7034	32729
2016	1230	5500	7139	33091
2017	1230	5800	7218	33259
2018	1230	5800	7077	33220
2019	1230	5800	7156	33019
2020	1230	5800	7014	32979
2021	1230	5800	6873	32377
2022	1230	5000	6512	31373
2023	1230	5000	6591	30610
2024	1230	5000	6670	30972
2025	1230	5000	6749	31334
2026	1230	5000	6828	31696
2027	1230	5000	6907	32058
2028	1230	5000	6986	32420

TABLE A5: TABLE A4 WITH DSM VARIATIONS

X Data	DSM x 2 Total Demand/Load MW	DSM x 2 Total Demand/Load GWh	DSM x 5 Total Demand/Load MW	DSM x 5 Total Demand/Load GWh
1990	3977	18634	3977	18634
1991	4045	19072	4045	19072
1992	4127	19427	4115	19367
1993	4788	22850	4764	22760
1994	4879	23543	4831	23303
1995	4896	24132	4800	23682
1996	4926	24456	4779	23706
1997	4994	24780	4787	23730
1998	5283	25801	5034	24541
1999	5349	27109	5076	25729
2000	5666	27865	5378	26425
2001	5926	29157	5626	27657
2002	6434	30870	6125	29340
2003	6493	32106	6175	30516
2004	6566	32123	6236	30473
2005	6109	29170	5767	27460
2006	6189	29220	5835	27450
2007	6228	29537	5862	27707
2008	6334	29864	5956	27974
2009	6387	30197	5997	28247
2010	6466	30540	6064	28530
2011	6541	30882	6127	28812
2012	6615	31224	6189	29094
2013	6690	31566	6252	29376
2014	6765	31908	6315	29658
2015	6880	31959	6418	29649
2016	6981	32301	6507	29931
2017	7056	32449	6570	30019
2018	6911	32390	6413	29900
2019	6986	32169	6476	29619
2020	6840	32109	6318	29499
2021	6695	31487	6161	28817
2022	6330	30463	5784	27733
2023	6405	29680	5847	26890
2024	6480	30022	5910	27172
2025	6555	30364	5973	27454
2026	6630	30706	6036	27736
2027	6705	31048	6099	28018
2028	6780	31390	6162	28300

TABLE A6: LA-1, NSP/UPA, EXISTING PLANT, DSM, DIVERSITY EXTENDED

	New Supply - New Plant		Total Demand/Load	
X Data	MW	GWh	MW	GWh
1990	0	100	3977	18634
1991	0	100	4045	19072
1992	0	100	4131	19447
1993	0	100	4796	22880
1994	0	100	4895	23623
1995	330	1657	4928	24282
1996	330	1773	4975	24706
1997	330	1773	5063	25130
1998	330	1773	5366	26221
1999	330	1773	5440	27569
2000	330	1773	5542	27943
2001	330	1773	5586	28291
2002	330	1773	5657	28648
2003	330	1532	5499	28377
2004	330	1773	5576	27852
2005	330	1973	5123	24919
2006	330	1973	5207	24989
2007	330	1973	5250	25326
2008	330	1973	5360	25673
2009	330	1973	5417	26026
2010	330	1973	5500	26389
2011	330	1973	5579	26751
2012	330	1973	5657	27113
2013	330	1973	5736	27475
2014	330	1973	5815	27837
2015	330	1973	5894	28199
2016	550	2514	5973	28561
2017	550	3304	6052	28923
2018	550	3304	6131	29285
2019	550	3304	6210	29647
2020	550	3304	6288	30009
2021	550	3304	6367	30371
2022	550	3304	6446	30733
2023	550	3304	6525	31095
2024	550	3304	6604	31457
2025	550	3304	6683	31819
2026	550	3304	6762	32181
2027	550	3304	6841	32543
2028	550	3304	6920	32905

TABLE A7: NSP/UPA, EXISTING PLANT, DSM, DIVERSITY EXTENDED, LE-2

X Data	New Supply - New Plant		Total Demand/Load	
	MW	GWh	MW	GWh
1990	0	100	3977	18634
1991	0	100	4045	19072
1992	0	100	4131	19447
1993	0	100	4796	22880
1994	0	100	4895	23623
1995	330	1657	4928	24282
1996	330	1773	4975	24706
1997	330	1773	5063	25130
1998	330	1773	5366	26221
1999	330	1773	5440	27569
2000	462	2173	5542	27943
2001	462	2173	5586	28291
2002	462	2173	5657	28648
2003	462	1932	5499	28377
2004	462	2173	5576	27852
2005	462	3238	5123	24919
2006	567	3838	5207	24989
2007	567	3838	5250	25326
2008	567	3838	5360	25673
2009	567	3838	5417	26026
2010	567	3838	5500	26389
2011	435	2573	5579	26751
2012	435	2573	5657	27113
2013	435	2573	5736	27475
2014	330	1973	5815	27837
2015	330	1973	5894	28199
2016	550	2514	5973	28561
2017	550	3304	6052	28923
2018	550	3304	6131	29285
2019	550	3304	6210	29647
2020	550	3304	6288	30009
2021	550	3304	6367	30371
2022	550	3304	6446	30733
2023	550	3304	6525	31095
2024	550	3304	6604	31457
2025	550	3304	6683	31819
2026	550	3304	6762	32181
2027	550	3304	6841	32543
2028	550	3304	6920	32905

TABLE A8: TABLE A7 WITH DSM VARIATIONS

	DSM x 2 Total Demand/Load		DSM x 5 Total Demand/Load	
X Data	MW	GWh	MW	GWh
1990	3977	18634	3977	18634
1991	4045	19072	4045	19072
1992	4127	19427	4115	19367
1993	4788	22850	4764	22760
1994	4879	23543	4831	23303
1995	4896	24132	4800	23682
1996	4926	24456	4779	23706
1997	4994	24780	4787	23730
1998	5283	25801	5034	24541
1999	5349	27109	5076	25729
2000	5446	27463	5158	26023
2001	5486	27791	5186	26291
2002	5554	28138	5245	26608
2003	5393	27847	5075	26257
2004	5466	27302	5136	25652
2005	5009	24349	4667	22639
2006	5089	24399	4735	22629
2007	5128	24716	4762	22886
2008	5234	25043	4856	23153
2009	5287	25376	4897	23426
2010	5366	25719	4964	23709
2011	5441	26061	5027	23991
2012	5515	26403	5089	24273
2013	5590	26745	5152	24555
2014	5665	27087	5215	24837
2015	5740	27429	5278	25119
2016	5815	27771	5341	25401
2017	5890	28113	5404	25683
2018	5965	28455	5467	25965
2019	6040	28797	5530	26247
2020	6114	29139	5592	26529
2021	6189	29481	5655	26811
2022	6264	29823	5718	27093
2023	6339	30165	5781	27375
2024	6414	30507	5844	27657
2025	6489	30849	5907	27939
2026	6564	31191	5970	28221
2027	6639	31533	6033	28503
2028	6714	31875	6096	28785

TABLE A9: NSP/UPA, EXISTING PLANT + CONAWAPA, DSM, LE-2, DIVERSITY EXTENDED, ONTARIO SALE

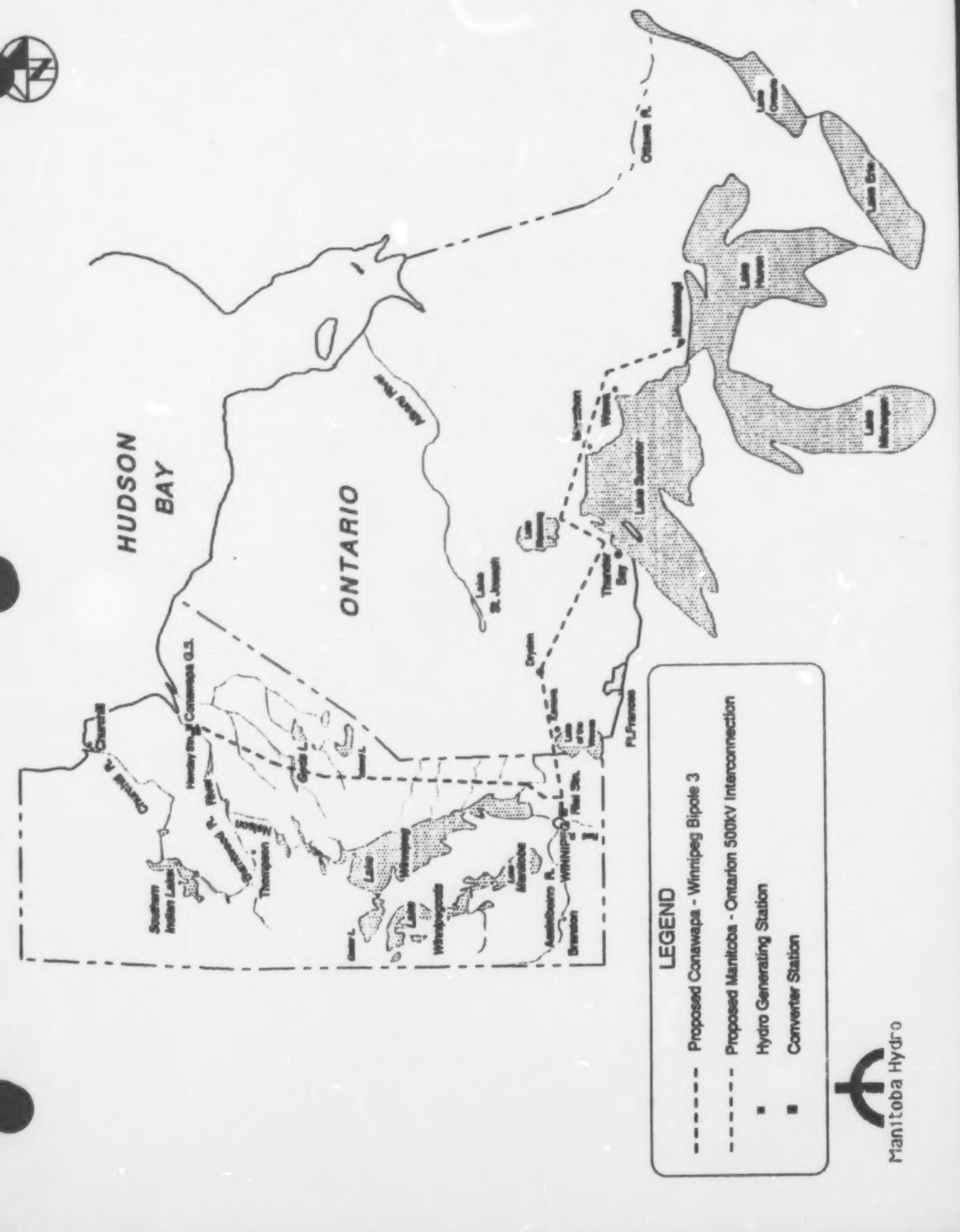
X Data	New Supply		Total Load	
	MW	GWh	MW	GWh
1990	0	100	3977	18634
1991	0	100	4045	19072
1992	0	100	4131	19447
1993	0	100	4796	22880
1994	0	100	4895	23623
1995	330	1657	4928	24282
1996	330	1773	4975	24706
1997	330	1773	5063	25130
1998	330	1773	5366	26221
1999	330	1773	5440	27569
2000	657	3383	5762	28345
2001	1087	6923	6026	29657
2002	1692	7473	6537	31380
2003	1692	7232	6599	32636
2004	1692	7473	6676	32673
2005	1692	8538	6223	29740
2006	1797	9138	6307	29810
2007	1797	9138	6350	30147
2008	1797	9138	6460	30494
2009	1797	9138	6517	30847
2010	1797	9138	6600	31210
2011	1665	7973	6679	31572
2012	1665	7973	6757	31934
2013	1665	7973	6836	32296
2014	1560	7373	6915	32658
2015	1560	7373	6994	33020
2016	1780	7914	7073	33382
2017	1780	8704	7152	33744
2018	1780	8704	7011	33705
2019	1780	8704	7090	33504
2020	1780	8704	6948	33464
2021	1780	8704	6807	32862
2022	1780	8704	6446	31858
2023	1780	8704	6525	31095
2024	1780	8704	6604	31457
2025	1780	8704	6683	31819
2026	1780	8704	6762	32181
2027	1780	8704	6841	32543
2028	1780	8704	6920	32905

TABLE A10: TABLE A9 WITH DSM VARIATIONS

	DSM x 2 Total Demand/Load		DSM x 5 Total Demand/Load	
X Data	MW	GWh	MW	GWh
1990	3977	18634	3977	18634
1991	4045	19072	4045	19072
1992	4127	19427	4115	19367
1993	4788	22850	4764	22760
1994	4879	23543	4831	23303
1995	4896	24132	4800	23682
1996	4926	24456	4779	23706
1997	4994	24780	4787	23730
1998	5283	25801	5034	24541
1999	5349	27109	5076	25729
2000	5666	27865	5378	26425
2001	5926	29157	5626	27657
2002	6434	30870	6125	29340
2003	6493	32106	6175	30516
2004	6566	32123	6236	30473
2005	6109	29170	5767	27460
2006	6189	29220	5835	27450
2007	6228	29537	5862	27707
2008	6334	29864	5956	27974
2009	6387	30197	5997	28247
2010	6466	30540	6064	28530
2011	6541	30882	6127	28812
2012	6615	31224	6189	29094
2013	6690	31566	6252	29376
2014	6765	31908	6315	29658
2015	6840	32250	6378	29940
2016	6915	32592	6441	30222
2017	6990	32934	6504	30504
2018	6845	32875	6347	30385
2019	6920	32654	6410	30104
2020	6774	32594	6252	29984
2021	6629	31972	6095	29302
2022	6264	30948	5718	28218
2023	6339	30165	5781	27375
2024	6414	30507	5844	27657
2025	6489	30849	5907	27939
2026	6564	31191	5970	28221
2027	6639	31533	6033	28503
2028	6714	31875	6096	28785

Appendix XIII
Proposed Transmission Additions

PROPOSED TRANSMISSION ADDITIONS


HUDSON BAY
ONTARIO
Churchill
Churchill R.
Southern Indian Lake
Henday Sta.
Conawapa G.S.
Nelson R.
Burntwood R.
Thompson
Gods L.
Island L.
Lake Winnipeg
Lake Winnipegosis
Lake Manitoba
Cedar L.
Assiniboine R.
Brandon
WINNIPEG
Red Riv.
Lake of the Woods
Kenora
Dryden
Ft.Frances
Thunder Bay
Lake Nipigon
Lake St. Joseph
Albany River
Lake Superior
Marathon
Wawa
Mississagi
Lake Huron
Lake Michigan
Lake Erie
Lake Ontario
Ottawa R.
LEGEND
Proposed Conawapa - Winnipeg Bipole 3
Proposed Manitoba - Ontarion 500KV Interconnection
Hydro Generating Station
Converter Station
Manitoba Hydro

Appendix XIV
Direct Benefits of the Ontario Sale

Direct Benefits of the Ontario Sale

1. Completion Schedule

Unit In-Service Date	Unit-Months Contract Year 2000-2001	2001-2002	2002-2003
Nov. 2000	11.5	12.0	12.0
Feb. 2001	8.5	12.0	12.0
May 2001	5.5	12.0	12.0
Aug. 2001	2.5	12.0	12.0
Nov. 2001	-	11.5	12.0
Jan. 2002	-	9.5	12.0
Mar. 2002	-	7.5	12
May 2002	-	5.5	12.0
Jul. 2002	-	3.5	12.0
Sep. 2002	-	1.5	12.0
	28.0	87.0	120.0

Notes

1. Units assumed in service at mid-month.
2. Unit net capacity taken as 129 MW, to reflect some non-quantified benefits. Otherwise (129 + 123)/2 would have been appropriate.
3. Unit net output taken as 7045/120 = 58.708455 GW.h/month.

Fixed Charge Rate for generation; 65 years, 5.5% real: = .056748
Fixed Charge Rate for transmission; 45 years, 5.5% real: = .060431

2. Annual Capital Cost

	2000-2001	2001-2002	2002-2003
Capital cost x FCR			
503 x .056748	28.54	28.54	28.54
912 x .056748	-	51.75	51.75
578 x .056748	-	-	32.80
387 x .060431	23.39	23.39	23.39
473 x .060431	-	28.58	28.58
299 x .060431	-	-	18.07
	51.93	132.26	183.13

3. Allocation Factors

Year	Capacity Sold MW	Plant (1) Capacity MW	Energy Sold GW.h	Plant Output GW.h	Allocation Factors Capital Cost	Allocation Factors Other Costs
2000-2001	200	301	1,403	1,644	.73090	.93875
2001-2002	400	935	2,805	5,108	.47059	.60405
2002-2003	800	1,290	4,295	7,045	.68217	.67062
2003-2018	1,000	1,290	5,698	7,045	.85271	.88968
2018-2019	800	1,290	4,558	7,045	.68217	.71168
2019-2020	800	1,290	4,558	7,045	.68217	.71168
2020-2021	600	1,290	3,419	7,045	.51163	.53384
2021-2022	400	1,290	2,279	7,045	.34109	.35584

Notes

1. Plant capacity is average for the period.
2. Allocation facors calculated as 1.1 x sale quantity/plant capability to account for losses.

4. Allocated Capital Cost

Year	Capital Cost (\$ x 10^6)	X	Allocation Factor	X	PW Factor	PW Nov. 1, 2000 (\$ x 10^6)
2000-2001	51.93		.73090		1.055(E-1)	36.0
2001-2002	132.26		.47059		1.055(E-2)	55.9
2002-2003	183.13		.68217		1.055(E-3)	106.4
2003-2018	183.13		.85271		(see Note)	1,334.9
2018-2019	183.13		.68217		1.055(E-19)	45.2
2019-2020	183.13		.68217		1.055(E-20)	42.8
2020-2021	183.13		.51163		1.055(E-21)	30.4
2021-2022	183.13		.34109		1.055(E-22)	19.2
						1,670.8

Note

Present worth summed as 1.055(E-3)(1.055(E-15) - 1)/(1.055(E-15)(.055).

5. Water Rentals

Year	Contract GW.h	Cost ($ x 10^6)	PW Factor	PW Nov. 1, 2000
2000-2001	1,403	2.28	.94787	2.2
2001-2001	2,805	4.57	.89845	4.1
2002-2003	4,295	6.99	.85161	6.0
2003-2018	5,698	9.28	8.54814	79.3
2018-2019	4,558	7.42	.36158	2.7
2019-2020	4,558	7.42	.34273	2.5
2020-2021	3,419	5.57	.32486	1.8
2021-2022	2,279	3.71	.30793	1.1
				99.7

Note

Cost calculated at 1.6285 mills/KW.h (in $1988).

Including losses and converting to ($1989):

99.7 x 1.1 x 1.05 = 115.2

6. Allocated Operating Cost and Overhead

Year	Amount (10 x 10^6)	Alocation Factor	PW Factor	PW Nov. 1, 2000
2000-2001	2.0	.93875	.96367	1.8
2001-2002	6.3	.60405	.92865	3.5
2002-2003	8.7	.67062	.89491	5.2
2003-2018	8.7	.88968	10.11153	78.3
2018-2019	8.7	.71168	.49499	3.1
2019-2020	8.7	.71168	.47700	3.0
2020-2021	8.7	.53384	.45967	2.1
2021-2022	8.7	.35584	.44297	1.4
				98.4

Note

MH apparently expects these costs to escalate at 6.75% per year in current dollars. They are here treated as constant 1989 dollar costs and discounted at 3.77%. (1.055 x 1.05/1.0675 = 1.0377)

7. **Revenue - Capacity Charge**

The base cost is $1,727/KW for the first 4 blocks and $1,603/Kw for the fifth, in 1988 dollars, escalating to the block in-service date. The fixed charge is taken as .10697 (40 years, 10.5%). The capacity payments in $(1989) millions for each block are:

Blocks 1 to 4:	1,727 x 1.05 x .2 x .10697	= $38.79
Block 5:	1,603 x 1.05 x .2 x .10697	= $36.01

Note that the charges are paid in current dollars, and are therefore discounted to the commencement date at 10.75% and then at 5.5% to November 1, 2000. The present worths are:

Block No.	**PW Factor**	**PW Nov. 1, 2000** ($ millions)
1	38.79(1.1075(E-20) - 1)/(.1075)(1.1075(E-20))1.055	297.6
2	As 1 above/1.055	282.1
3	As 2 above/1.055	267.4
4	As 3 above	267.4
5	36.01(1.1075(E-15) - 1)/(.1075)(1.1075(E-15))(1.055(E-4))	211.9
		1,326.4

8. **Revenue - Energy**

Year	**GW.h**	**X**	**Price /KW.h** ($1988)	**X**	**PW Factor**	**PW Nov. 1, 2000** ($ millions)
2000-2001	1,403		.02210		.94787	29.4
2001-2002	2,805		"		.89845	55.7
2002-2003	4,295		"		.85161	80.8
2003-2018	5,698		"		8.54814	1,076.4
2018-2019	4,558		"		.36158	36.4
2019-2020	4,558		"		.34273	34.5
2020-2021	3,419		"		.32486	24.5
2021-2022	2,279		"		.30793	15.5
						1,353.2

Converting to ($1989);1,353.2 x 1.05 = 1,420.9

9. **Summary**

Item	PW 2,000 ($ millions)	Discount Rate	PW 1989 ($ million)
Capacity charge	1,326.4	1.055	736.0
Energy charge	1,420.9	1.055	788.5
Total Revenue	2,747.3		1,524.5
Debt charges	1,670.8	1.055	927.1
Water rentals	115.2	1.055	63.9
Other costs	98.4	1.0377	65.5
Total Expenses	1,884.4		1,056.5
Net benefit	862.9		468.0

Appendix XV
CAC/MSOS' Calculation of the Net Benefit of the Ontario Sale

(Source: Exhibit #CAC/MSOS-8)

Calculation of Net Profit (Loss) on Sale of Marginal Supply to Ontario Hydro by Year
($millions)

				Marginal Supply								
Year	Year	New G.S. (1)	OH Sale (GW.h) (2)	Conawapa (7045) 2.72 (3)	Wuskwat. (2200) 2.15 (4)	Birthday (3265) 2.39 (5)	Manasan (1670) 3.17 (6)	First Rap (1400) 2.94 (7)	Wtd. Cost (1990$) (8)	Ontario Sale Revenue (Curr $) (9)	Ontario Sale Revenue (1990$) (10)	Net Profit/ Loss (1990$) (11)
2000	2000	Conawapa										
2001	2001		701	701					19	66	39	20
2002	2002		2104	2104					57	232	129	72
2003	2003		3550	3550					97	448	238	141
2004	2004		4997	4997					136	699	353	217
2005	2005		5698	5698					155	817	393	238
2006	2006		5698	5698					155	642	294	139
2007	2007	Wuskwatim	5698	5698					155	657	287	132
2008	2008		5698	5698					155	672	279	124
2009	2009		5698	5698					155	688	272	117
2010	2010		5698	5698					155	704	265	110
2011	2011	Birthday	5698	5698					155	722	259	104
2012	2012		5698	2433		3265			161	740	253	92
2013	2013		5698	2433		3265			161	570	186	25
2014	2014	Manasan	5698	2433		3265			161	585	181	21
2015	2015	First Rap	5698	763		3265	1670		168	601	177	9
2016	2016		5698			2628	1670	1400	170	618	174	4
2017	2017		5698			2628	1670	1400	170	635	170	0
2018	2018		5698			2628	1670	1400	170	654	167	-3
2019	2019		5128			2058	1670	1400	154	617	150	-4
2020	2020		4558			1488	1670	1400	137	555	128	-9
2021	2021		3989			919	1670	1400	121	514	113	-7
2022	2022		2849				1449	1400	87	384	81	-7
2023	2023		1140					1140	34	180	36	2
TOTAL	TOTAL		108,788	59,300	0	25,409	13,139	10,940	$3,085	$13,000	$4,624	$1,539

Notes: Figures under name of plants in columns 3 through 7 are:

- the average energy in GW.h. per CAC/MSOS/MH (R) 5,
- the levelized cost (cents/kW.h) for actual in-service date in constant 1990 dollars per CAC/MSOS/MH (R) 5.

Weighted cost in column 8 is sum of marginal supplies multiplied by the corresponding levelized cost.

Column 11 equals column 10 minus column 8.

Appendix XVI
Contracts with Ontario Hydro

SYSTEM PARTICIPATION AGREEMENT

MANITOBA-ONTARIO INTERCONNECTION

between

THE MANITOBA HYDRO-ELECTRIC BOARD

and

ONTARIO HYDRO

DECEMBER 7,1989

MANITOBA - ONTARIO POWER TRANSACTION AGREEMENT

THIS AGREEMENT ("Agreement") is made and entered into this 7th day of December, 1989 by and between Ontario Hydro, an Ontario statutory corporation of the first part, and The Manitoba Hydro-Electric Board ("Manitoba Hydro"), a Manitoba Crown corporation of the second part, (each of the foregoing entities being sometimes referred to individually as "Party" and both being sometimes collectively referred to as "Parties").

WITNESSETH:

0.01 WHEREAS, Ontario Hydro and Manitoba Hydro are the owners and operators of electric generation and transmission facilities in Ontario and in Manitoba, respectively, and are engaged in the generation, transmission and distribution of electric energy; and

0.02 WHEREAS, the systems of Ontario Hydro and Manitoba Hydro are interconnected by transmission lines and are operating in synchronism; and

0.03 WHEREAS, Manitoba Hydro requires the approval of The Manitoba Energy Authority for the import into and export from the Province of Manitoba of capacity and energy, and Manitoba Hydro has been granted by such Authority approval to enter into this Agreement and to export capacity and energy as required by this Agreement; and

0.04 WHEREAS, Ontario Hydro has requested Manitoba Hydro to make capacity and energy available to Ontario Hydro during the period hereinafter referred to; and

0.05 WHEREAS, Manitoba Hydro has agreed to make capacity and energy available to Ontario Hydro during the period hereinafter referred to, subject to the terms and conditions hereinafter set forth; and

0.06 WHEREAS, when Ontario Hydro and Manitoba Hydro execute and deliver this Agreement, they have also agreed to execute and deliver concurrently the Manitoba - Ontario Facilities Agreement (the "Facilities Agreement") for the purpose of constructing facilities which will allow the transactions described herein to take place.

NOW THEREFORE, the Parties agree as follows:

ARTICLE 1
DEFINITIONS

For the purposes of this Agreement, the following definitions shall apply:

1.01 Annual Capacity Factor - expressed as a percentage, shall mean with respect to a particular Contract Year:

- a. the Energy delivered during the Contract Year, divided by;
- b. the product of:
  - i. the amount of Capacity required to be made available in the Contract Year, and
  - ii. the number of hours in the Contract Year.

1.02 Capacity - shall mean for any Contract Year the capacity described in Section 2.01.

1.03 Capacity Unavailability - shall be as defined in Schedule 4 to this Agreement.

1.04 Consumer Price Index - shall, except as provided in Section 9.08, mean the Index so described in Schedule 2.

1.05 Contract Term - shall mean the period from 00:00 hours Eastern Standard Time on the commencement date, November 1, 2000, through to 24:00 hours Eastern Standard Time on the termination date, October 31, 2022.

1.06 Contract Year - shall mean each twelve-month period of time during the Contract Term beginning at 00:00 hours Eastern Standard Time on November 1 of any calendar year and ending at 24:00 hours Eastern Standard Time on October 31 of the next calendar year.

1.07 Day - shall mean a period of twenty-four consecutive hours commencing at 00:00 hours Eastern Standard Time or such other period as may from time to time be agreed upon by the Operating Committee.

1.08 Deferred Energy - shall be as defined in Section 6.06 of this Agreement.

1.09 Energy - shall mean for any Contract Year the energy described in Section 2.01 or where the context so requires, a portion thereof.

1.10 Firm Commitments - shall mean capacity and energy intended by Manitoba Hydro to be available at all times during the period covered by a commitment.

1.11 Hydro Electric Generating Station Construction Price Index - shall, except as provided in Section 9.08, mean the Index so described in Schedule 1.

1.12 Interconnection Agreement - shall mean the Interconnection Agreement between Manitoba Hydro and Ontario Hydro dated November 16, 1971, and any subsequent amendments or complete replacements in effect during the term of this Agreement.

1.13 Interconnection Facilities - shall mean the existing facilities which interconnect the systems of the Parties and the New Interconnection Facilities described in Section 2.01 of the Facilities Agreement.

1.14 Low Flow Conditions - shall be a forecast condition in any Month when the amount of electric energy imported into Manitoba is expected to exceed the amount of electric energy exported from Manitoba. For such purpose, "energy exported from Manitoba" shall not include energy exported from Manitoba pursuant to Firm Commitments made more than six Months prior to said Month.

1.15 Month - shall mean a period commencing at 00:00 hours Eastern Standard Time on the first Day of a calendar month and ending at 24:00 hours Eastern Standard Time on the last Day of that calendar month.

1.16 Monthly Capacity Charge - shall mean the charge provided for in Section 8.01.

1.17 Monthly Capacity Entitlement - shall be as defined in Schedule 4 to this Agreement.

1.18 Monthly Capacity Factor - expressed as a percentage, shall mean with respect to a particular Month:

a. the Energy delivered during the Month, divided by;

b. the product of:

  i. the amount of Capacity required to be made available in the Month, and

  ii. the number of hours in the Month.

1.19 Monthly Capacity Rate - shall mean the rate defined in Schedule 1.

1.20 Monthly Energy Rate - shall mean in respect of a Month the rate charged for energy for such Month determined pursuant to Schedule 2.

1.21 Operating Committee - shall mean the Operating Committee established pursuant to the Interconnection Agreement.

1.22 Point of Interconnection - shall be the points where the Interconnection Facilities intersect the boundary between the Provinces of Manitoba and Ontario.

1.23 Supplemental Energy - shall be in any Month in a Contract Year, the energy described in Article 10, which is in addition to the Energy.

1.24 Supplementary Agreement - shall mean an instrument in writing duly authorized and executed by the Parties which alters, amends, varies, modifies, or waives any right under, any provision of this Agreement or of the Facilities Agreement.

1.25 System Participation Power - shall be the Capacity and the Energy.

1.26 Week - shall mean a period of seven consecutive Days commencing on Monday at 00:00 hours Eastern Standard Time, or on such other Day or hour as may from time to time be agreed upon by the Operating Committee.

1.27 Year - shall mean any twelve-month period of time beginning at 00:00 hours Eastern Standard Time on November 1 of any year and ending at 24:00 hours Eastern Standard Time on October 31, of the next year.

ARTICLE 2
SYSTEM PARTICIPATION POWER

2.01 Except as hereinafter provided in this Agreement, Manitoba Hydro shall at all times in each Contract Year reserve and make available to Ontario Hydro the following capacity at the Point of Interconnection in accordance with the block structure set out in Schedule 1:

Contract Year	Period	Capacity
1	November 1, 2000 to October 31, 2001	200 000 kW
2	November 1, 2001 to October 31, 2002	400 000 kW
3	November 1, 2002 to October 31, 2003	800 000 kW
4 to 18	November 1, 2003 to October 31, 2018	1 000 000 kW
19 to 20	November 1, 2018 to October 31, 2020	800 000 kW
21	November 1, 2020 to October 31, 2021	600 000 kW
22	November 1, 2021 to October 31, 2022	400 000 kW

Subject to Sections 6.03 and 6.05, Manitoba Hydro shall supply, and subject to Section 6.06, Ontario Hydro shall purchase and schedule for delivery the following energy in each Contract Year:

Contract Year	Period	Energy	Annual Capacity Factor
1	November 1, 2000 to October 31, 2001	1 403 GWh	80%
2	November 1, 2001 to October 31, 2002	2 805 GWh	80%
3	November 1, 2002 to October 31, 2003	4 295 GWh	61%
4 to 18	November 1, 2003 to October 31, 2018	5 698 GWh	65%
19 to 20	November 1, 2018 to October 31, 2020	4 558 GWh	65%
21	November 1, 2020 to October 31, 2021	3 419 GWh	65%
22	November 1, 2021 to October 31, 2022	2 279 GWh	65%

2.02 The commitments contained in Section 2.01 are in addition to the commitments contained in the Electricity Sale Agreement dated August 28, 1987 made between Manitoba Hydro, The Manitoba Energy Authority and Ontario Hydro.

ARTICLE 3
COMMITTEES

3.01 The Operating Committee shall have responsibility for all things necessary to coordinate delivery and billing of System Participation Power, Deferred Energy and Supplemental Energy in accordance with this Agreement.

3.02 The Interconnection Agreement shall not be terminated so long as this Agreement remains in full force and effect.

ARTICLE 4
MEASUREMENT OF CAPACITY AND ENERGY

4.01 Capacity made available and energy delivered at the Point of Interconnection shall be metered on the metering equipment installed pursuant to the Interconnection Agreement and/or the Facilities Agreement on the transmission lines crossing the boundary between the Provinces of Manitoba and Ontario. An appropriate allowance, as determined by the Operating Committee, shall be made in all measurements for line losses between the metering point or points and the Point of Interconnection.

ARTICLE 5
DELIVERY

5.01 Capacity shall be made available and energy shall be delivered at the Point of Interconnection, unless otherwise agreed by the Operating Committee. In the event of the failure of the Interconnection Facilities or any other facilities in either Manitoba or Ontario, which failure affects the ability to make available, deliver or receive System Participation Power, Deferred Energy or Supplemental Energy, the Parties shall consider making available, delivering and receiving the System Participation Power, Deferred Energy or Supplemental Energy, by such other means as are available.

5.02 Ontario Hydro and Manitoba Hydro shall use their respective best efforts to develop and implement measures designed to maintain reliable operation of the Interconnection Facilities and to minimize the extent to which failures on the system of one Party adversely affect the reliable operation of the system of the other Party.

5.03 Subject to Article 11 and Section 13.01, each Party shall ensure that the transmission facilities within its Province, required to be constructed by it in order to make available, deliver or receive the System Participation Power, are constructed and ready for service on or before November 1, 2000.

5.04 Each Party shall operate and maintain its portion of the Interconnection Facilities in accordance with the guidelines set forth in the Interconnection Agreement.

5.05 All System Participation Power, Deferred Energy and Supplemental Energy delivered pursuant to this Agreement shall normally be delivered at unity power factor at the Point of Interconnection unless otherwise agreed by the Operating Committee.

ARTICLE 6
CONDITIONS OF SERVICE

6.01 The System Participation Power is intended to be available at all times to Ontario Hydro with a high degree of assurance. In this regard, it is Manitoba Hydro's intention to plan, develop and subsequently operate its resources so that the Capacity Unavailability (U) does not exceed four and one-quarter percent (4.25%) of the Monthly Capacity Entitlement (Q) during the critical winter months, October through March. Manitoba Hydro shall exercise due diligence and reasonable care and foresight to make the System Participation Power available to Ontario Hydro, and when planning the development of its system shall not consider the Capacity as part of its planned reserve capacity, and when operating its system shall not consider the Capacity as part of its operating reserve requirement.

6.02 Unless otherwise agreed by the Operating Committee, Ontario Hydro shall, subject to Section 6.05 and in accordance with the procedures set out in Section 7.01:

a. have the flexibility to schedule delivery of Energy at up to eighty percent (80%) Monthly Capacity Factor;

b. schedule delivery of Energy up to the amount for each Contract Year; and

c. schedule delivery of Energy in any hour at a rate not less than fifteen percent (15%) of the Capacity for such Contract Year.

6.03 If conditions arise which affects Manitoba Hydro's ability to make available or deliver the System Participation Power, Deferred Energy and Supplemental Energy as scheduled by Ontario Hydro, Manitoba Hydro may, notwithstanding Section 6.01 and subject to Section 6.08, curtail availability and deliveries by the amount necessary to enable Manitoba Hydro to meet:

a. Firm Commitments within Manitoba, including obligations now existing or hereafter created to retail customers within the Province of Manitoba (including retail customers presently served by Manitoba Hydro which are outside the Province of Manitoba but are located adjacent to a Province of Manitoba border and any future customers similarly located, in each case with less than 10 megawatts peak demand), and obligations now existing or hereafter created to other electric suppliers to serve retail customers within the Province of Manitoba.

b. The 500,000 kilowatt sale to Northern States Power Company as set out in the original June 14, 1984, Power Agreement between Northern States Power Company, Manitoba Hydro and The Manitoba Energy Authority (the "NSP Agreement"), provided the deliveries under the NSP Agreement shall be reduced to the extent permitted under the terms of Article 1 of the NSP Agreement attached in Schedule 3 to this Agreement, before availability or deliveries under this Agreement are curtailed.

c. The Island Falls Power and Energy Transfer Agreement between Manitoba Hydro and Saskatchewan Power Corporation dated January 15, 1985.

d. The original August 28, 1987, Electricity Sale Agreement between Manitoba Hydro, The Manitoba Energy Authority and Ontario Hydro.

e. The original November 16, 1987, Diversity Exchange Agreement between Northern States Power Company and Manitoba Hydro.

Manitoba Hydro shall provide as much notice as possible of pending curtailments and shall be prompt and diligent in resuming availability and deliveries to the scheduled amounts.

6.04 If Manitoba Hydro curtails scheduled Capacity deliveries that have been mutually established pursuant to Section 7.01, as a result of a curtailment pursuant to Section 6.03 or as a result of a curtailment due to an event within the Manitoba Hydro system as contemplated by Section 13.04, the Capacity Unavailability shall be calculated pursuant to Schedule 4. If such Capacity Unavailability (U) in any Month exceeds four and one-quarter percent (4.25%) of the Monthly Capacity Entitlement (Q), then, notwithstanding the provisions of Section 13.04, a reduction in the Monthly Capacity Charge for such Month shall be made, calculated as follows:

Commencing from the time of the Month when the Capacity Unavailability reaches four and one-quarter percent (4.25%), all curtailments thereafter of thirty (30) consecutive minutes or more, as a result of a curtailment pursuant to Section 6.03 or as a result of a curtailment due to an event within the Manitoba Hydro system as contemplated by Section 13.04, shall be identified and the formula set out below shall be applied:

$$(0.06) \times (\bar{A}) \times \sum_{j=1}^{n} (X_j)$$

where:

$\bar{A}$ is the average of the Monthly Capacity Rates applicable to the blocks of Capacity for such Month calculated in accordance with Schedule 1, expressed in dollars per kilowatt per Month.

n is the number of Days in such Month from and including the Day in which the Capacity Unavailability reaches four and one-quarter percent (4.25%) in which a Capacity curtailment of duration equal to or greater than thirty minutes is reached or remains in effect.

X_j is the maximum reduction in kilowatts from the hourly schedule during each Day when such curtailment(s) occurred.

However, the total reduction for any given Month shall not exceed the Monthly Capacity Charge for that Month as calculated pursuant to Section 8.01.

6.05 In the event that Manitoba Hydro forecasts Low Flow Conditions in any Month, Manitoba Hydro may, in accordance with the procedures set out in Section 7.01, curtail the Energy, and/or subject to Section 6.08, curtail the Deferred Energy to be delivered to Ontario Hydro in such Month to the lesser of:

a. the level permitted under Section 6.03, or

b.. the level that results from a curtailment equal to the lesser of:

   i. the amount of energy necessary to avoid Low Flow Conditions; and

   ii. the amount which would reduce deliveries to fifty (50) percent Monthly Capacity Factor for such Month.

6.06 Deferred Energy shall be determined for each Contract Year at the end of such Contract Year and shall be the lesser of:

a. the Energy scheduled by Ontario Hydro in such Contract Year that was curtailed by Manitoba Hydro by reason of a curtailment under Section 6.03 or Section 6.05 or as a result of events affecting either Party as contemplated by Section 13.04, and

b. the amount of Energy not delivered in such Contract Year.

Ontario Hydro shall not be obligated to purchase or schedule deliveries of Deferred Energy, and Ontario Hydro's obligation to purchase Energy in such Contract Year is reduced by the amount of Deferred Energy in such Contract Year.

6.07 Ontario Hydro has the right to schedule delivery of Deferred Energy from a Contract Year within the sixty-month period after the end of such Contract Year. Unless otherwise agreed by the Operating Committee, the Capacity being reserved by Manitoba Hydro during the Contract Term shall be utilized for delivery of the Deferred Energy and Manitoba Hydro has no obligation to provide additional capacity to permit delivery of Deferred Energy.

6.08 Manitoba Hydro shall make available Deferred Energy from a Contract Year within the sixty-month period after the end of such Contract Year. If Ontario Hydro does not schedule Deferred Energy for delivery when it is made available within the said sixty-month period, Manitoba Hydro has no further obligation to provide such Deferred Energy. In the sixty-month period following the Contract Term, scheduling of Deferred Energy shall be determined by the Operating Committee and the Monthly Energy Charge shall be calculated pursuant to Section 8.02 with F in Schedule 2 equal to 0.75.

For the purposes of this Section 6.08, Deferred Energy which has been made available by Manitoba Hydro and is scheduled by Ontario Hydro, but:

a. during the Contract Term, is curtailed by Manitoba Hydro pursuant to Section 6.03 or 6.05, or as a result of an event within the Manitoba Hydro system pursuant to Section 13.04; or

b. during the sixty-month period following the Contract Term, is curtailed by Manitoba Hydro,

such curtailed Deferred Energy shall continue to be Deferred Energy.

6.09 The Operating Committee if its members so agree may reschedule delivery of the Energy and Deferred Energy from one Year to the next during the Contract Term, and may reschedule delivery of Deferred Energy during the sixty-month period of time following the Contract Term.

6.10 If Manitoba Hydro, pursuant to Section 6.03 or Section 6.05 or as a result of events contemplated by Section 13.04, curtails availability or delivery of System Participation Power to Ontario Hydro, then at Ontario Hydro's request, Manitoba Hydro shall exercise its best efforts to find alternate sources of capacity and energy in excess of Manitoba Hydro's requirements through purchase arrangements if available. If Ontario Hydro elects to purchase such capacity and energy, all capacity and energy charges incurred by Manitoba Hydro in connection with such purchases shall be paid by Ontario Hydro. Such purchased capacity and energy shall not be considered part of the System Participation Power. Notwithstanding any such purchases, Sections 6.04 and 6.06 shall continue to apply in respect of each such curtailment.

ARTICLE 7
SCHEDULING

7.01 Unless otherwise agreed by the Operating Committee, the following procedures shall apply for scheduling availability and deliveries of System Participation Power pursuant to this Agreement:

a. Monthly

At least seven (7) Days in advance of each Month of each Contract Year, Ontario Hydro shall provide Manitoba Hydro with a schedule of required availability and deliveries for each Week of the Month (the "Original Schedule") and an estimate of required availability and deliveries for the following Month.

Before the first Day of each Month of each Contract Year, Manitoba Hydro shall provide Ontario Hydro with a schedule of any energy curtailments from the Original Schedule and from Ontario Hydro's estimate for the following Month which are forecast to occur pursuant to Section 6.05. For the purposes of Section 6.06, the energy curtailed by reason of a curtailment pursuant to Section 6.05 shall be this energy curtailment from the Original Schedule.

On or before the first Day of each Month of each Contract Year, Ontario Hydro shall provide Manitoba Hydro with a revised schedule of availability and deliveries as required for each Week of the Month based on Manitoba Hydro's forecasted energy curtailments.

b. Weekly

On or before 17:00 hours Eastern Standard Time on Sunday of each Week of each Contract Year, Ontario Hydro shall provide Manitoba Hydro with a schedule of required availability and deliveries for each Day of the following Week. The daily schedules shall be within the schedule for the Month unless otherwise mutually agreed.

c. Daily

On or before 17:00 hours Eastern Standard Time of each Day of each Contract Year, Ontario Hydro shall provide Manitoba Hydro with an hourly schedule of required availability and deliveries within the daily schedule for the following Day. These schedules shall be followed unless otherwise mutually agreed.

7.02 Ontario Hydro shall use all reasonable efforts to follow the daily schedule but may, after 17:00 hours Eastern Standard Time of the previous Day, request daily availability and deliveries at levels different from those scheduled, for reasons unforeseen when the daily schedule was established. In such case, Manitoba Hydro shall use all reasonable efforts to comply with such requests.

ARTICLE 8
SCHEDULE OF RATES

8.01 Subject to reduction pursuant to Section 6.04, Ontario Hydro shall pay each Month a capacity charge for the Capacity calculated as follows:

Contract Year	Monthly Capacity Charge (dollars)
1	$200\ 000 \times A_1$
2	$200\ 000 \times (A_1 + A_2)$
3	$200\ 000 \times (A_1 + A_2 + A_3 + A_4)$
4 to 18	$200\ 000 \times (A_1 + A_2 + A_3 + A_4 + A_5)$
19 to 20	$200\ 000 \times (A_1 + A_2 + A_3 + A_4)$
21	$200\ 000 \times (A_2 + A_3 + A_4)$
22	$200\ 000 \times (A_3 + A_4)$

where:

A_1 to A_5 are the Monthly Capacity Rates expressed in dollars per kilowatt applicable to each Contract Year calculated for each block as described in Schedule 1.

8.02 For Energy and Deferred Energy delivered by Manitoba Hydro to Ontario Hydro, the energy charge to be paid by Ontario Hydro each Month shall be calculated as follows:

Monthly Energy Charge (in dollars) = B x Energy plus Deferred Energy delivered in that Month expressed in megawatt hours

where:

B is the Monthly Energy Rate expressed in dollars per megawatt hour calculated as described in Schedule 2.

8.03 In respect of each Contract Year, Ontario Hydro shall pay Manitoba Hydro for the Capacity and Energy whether or not such Capacity is utilized or such Energy is scheduled for delivery; provided however, that Ontario Hydro shall not be obligated to pay for Deferred Energy unless delivered to Ontario Hydro and that Ontario Hydro shall receive the reduction in the Monthly Capacity Charge as specified in Section 6.04 if applicable. At the end of each Contract Year the portion of Energy which was scheduled for delivery by Ontario Hydro shall be determined and if that amount is less than the Energy, an additional payment for Energy shall be due and payable and shall be based upon the average of the Monthly Energy Rates for the

Contract Year. The amount of Energy shall be adjusted in accordance with E_D and E_C as described below. This additional payment shall not be less than zero and shall be calculated using the quantities for such Contract Year as follows:

$$(E - E_D - E_C) \times B_{13}$$

where:

E is the Energy.

E_D is the amount of Energy actually delivered.

E_C is the cumulative amount of Energy not delivered by Manitoba Hydro as a result of curtailment pursuant to Section 6.03 or Section 6.05 or as a result of events within the Manitoba Hydro system contemplated by Section 13.04. Said amount shall not include Energy scheduled by Ontario Hydro that was curtailed by Manitoba Hydro as a result of events within the Ontario Hydro system contemplated by Section 13.04.

B_{13} is the average of the twelve Monthly Energy Rates for such Contract Year as determined in Schedule 2.

ARTICLE 9
BILLING

9.01 Bills shall be delivered monthly by Manitoba Hydro to Ontario Hydro by any means as designated by the Operating Committee, including without limitation, telex, telecopier, or other electronic means with acknowledgement of receipt requested, normally not later than fifteen calendar days after the end of the period covered by such bill. In the event that all quantities and values are not accurately known in time for the preparation of the monthly bill, estimated quantities and values may be used to prepare an interim bill with a final bill to be prepared when accurate quantities and values become known. Interest in accordance with Section 9.06 shall accrue and be paid on any overpayments or underpayments, as the case may be.

9.02 The period for billing shall be from 00:00 hours Eastern Standard Time of the first Day of the Month to 24:00 hours Eastern Standard Time of the last Day of that Month.

9.03 Bills shall be deemed rendered upon receipt by Ontario Hydro. Payment of all bills shall be due and payable fourteen (14) calendar days after the date the bill is rendered. If such due date falls on a Saturday, Sunday or a holiday observed by either Party, the payment shall be due and payable on the next following business day common to both Parties. Interest in accordance with Section 9.06 shall accrue and be paid on any overdue or unpaid balances.

9.04 In the event Ontario Hydro desires to dispute all or any part of a bill submitted by Manitoba Hydro pursuant to this Agreement, Ontario Hydro shall nevertheless pay the full amount of the bill when due and payable, and shall give notice to Manitoba Hydro within sixty days from the date the bill is rendered setting forth the specific details upon which the bill is disputed and the amount thereof in dispute. Ontario Hydro shall not be entitled to any adjustment on account of any bill for which notice is not given in accordance with the preceding sentence. If the resolution of a dispute regarding a bill results in a refund, interest in accordance with Section 9.06 shall be added to and paid with the refund.

9.05 Notwithstanding any other provision in this Agreement, each Party shall be solely responsible for the payment of all fines, levies, taxes, fees and royalties on the import or export of capacity or energy imposed on it directly or indirectly by any federal legislation or any provincial or municipal legislation of the province in which its headquarters are located, without any right of reimbursement in whole or in part from the other Party.

9.06 For the purposes of this Agreement interest shall accrue and be determined daily using for each Day the rate equal to the prime lending rate expressed as a rate per annum which the Canadian Imperial Bank of Commerce at its main office in the City of Winnipeg, Manitoba (or such other bank as the Operating Committee determines) establishes as a reference rate of interest in order to determine interest rates it will charge on that Day for loans in Canadian dollars made in Canada to its most favoured Canadian commercial customers. Each such daily interest determination shall be computed on the basis of actual Days and the number of Days in the applicable calendar year.

9.07 Payment of all bills shall be made by interbank transfer of immediately available same day Canadian funds to a bank designated by Manitoba Hydro. Payment shall be deemed made when received by the designated bank.

9.08 If the Consumer Price Index, Catalog No. 62-001, and/or the Hydro Electric Generating Station Construction Price Index, Catalogue No. 62-007 are no longer available, the

Operating Committee shall choose a suitable replacement or replacements. If either such index is changed so as to make use of or reflect a different base, the Operating Committee may choose a suitable replacement. In any such case, the replacement index shall thereafter replace the original index for all purposes of this Agreement effective at a time designated by the Operating Committee.

ARTICLE 10
SUPPLEMENTAL ENERGY

10.01 Subject to Sections 10.02 and 10.03, Manitoba Hydro shall make available and Ontario Hydro may at its option purchase energy in addition to the Energy during the Contract Term as follows:

Contract Year	Period	Energy
1	November 1, 2000 to October 31, 2001	22 GWh/Month
2	November 1, 2001 to October 31, 2002	44 GWh/Month
3	November 1, 2002 to October 31, 2003	88 GWh/Month
4 to 18	November 1, 2003 to October 31, 2018	110 GWh/Month
19 to 20	November 1, 2018 to October 31, 2020	88 GWh/Month
21	November 1, 2020 to October 31, 2021	66 GWh/Month
22	November 1, 2021 to October 31, 2022	44 GWh/Month

10.02 In the event that Manitoba Hydro forecasts Low Flow Conditions in any Month (but without taking into account Supplemental Energy), Manitoba Hydro may limit the supply of Supplemental Energy to Ontario Hydro to zero in such Month. In the event that delivery of Ontario Hydro's scheduled requirements for Supplemental Energy will create Low Flow Conditions in any Month, Manitoba Hydro may limit delivery of Supplemental Energy in such Month to the amount of energy that Manitoba Hydro is able to supply without creating Low Flow Conditions.

10.03 Ontario Hydro has the right to schedule Supplemental Energy utilizing the Capacity reserved in accordance with Section 2.01, it being understood that Manitoba Hydro is not required to plan or develop its resources to make Supplemental Energy available.

10.04 Manitoba Hydro may at its option agree to deliver Supplemental Energy utilizing capacity levels in excess of those specified in Section 2.01.

10.05 The charge for Supplemental Energy delivered in a Month by Manitoba Hydro to Ontario Hydro shall be calculated as follows:

$$\text{Supplemental Energy Charge (in dollars)} = \frac{\$18/\text{megawatt}}{\text{hour}} \times \frac{CPI}{CPI_B} \times \text{Supplemental Energy delivered in that Month expressed in megawatt hours}$$

where:

CPI_B is the Consumer Price Index for July, 1988, which is 144.5 (1981 = 100).

CPI is the Consumer Price Index for the Month three Months previous to the billing Month on the 1981 base.

ARTICLE 11
APPROVALS

11.01 Each Party shall use its best efforts to expeditiously obtain any and all Orders-in-Council, approvals, licences, permits, permission, consents, certificates and orders (hereinafter individually and collectively referred to as "the approvals") required by it in order for it to be able lawfully to carry out the transactions contemplated by this Agreement and the design, construction, development, operation and maintenance of its portion of the facilities required to deliver and receive the System Participation Power. Each Party shall keep the other Party informed as to the status of the approvals it is seeking; provided however that each Party may, at its sole discretion, design, construct, develop, operate and maintain its facilities without regard to the status of the other Party's approval process, and neither Party shall later object to a cost or expense contemplated by Section 11.04 on the basis that the other Party should not have incurred such cost or expense given the status of any approval process.

11.02 This Agreement shall be subject to the condition that on or before December 31, 1990 the Manitoba Public Utilities Board issues its recommendations in relation to Manitoba Hydro's long-term capital plan that incorporates the terms and conditions of this Agreement. The recommendations shall be evidenced by report of the Public Utilities Board. If the recommendations are not issued by that date in form and content acceptable to Manitoba Hydro, Manitoba Hydro has the option to terminate this Agreement and the Facilities Agreement effective that date by notice in writing delivered to Ontario Hydro on or before

December 31, 1990, and each Party shall be responsible only for its own costs to that date. This condition is solely for the benefit of Manitoba Hydro.

11.03 This Agreement shall be subject to the condition that the requirement on Ontario Hydro as provided in Section 5 (3) (b) of the Environmental Assessment Act, R.S.O. 1980 c.140, as amended, to describe and state the rationale for the transmission facilities in Ontario required to receive the System Participation Power, be accepted and approved or otherwise satisfied on or before December 31, 1990. The acceptance and approval or other satisfaction of the requirement referred to above shall be evidenced by the decision of the board hearing the matter or by an Order-in-Council as the case may be. If the acceptance and approval are not obtained or the requirement is not otherwise satisfied by that date in form and content acceptable to Ontario Hydro, Ontario Hydro has the option to terminate this Agreement and the Facilities Agreement effective that date by notice in writing delivered to Manitoba Hydro on or before December 31, 1990, and each Party shall be responsible only for its own costs to that date. This condition is solely for the benefit of Ontario Hydro.

11.04 If any of the approvals is not obtained on or before December 31, 1990, the Party ("Terminating Party") who sought and has not obtained the approval may at any time thereafter and prior to the date on which such approval is obtained give notice (the "Termination Notice") of termination of this Agreement to the other Party (the "Other Party"). With all reasonable dispatch after receipt by it of the Termination Notice, the Other Party shall supply to the Terminating Party a certificate (the "Certificate"), signed by a senior officer of the Other Party, setting out in detail the costs (both internal and out-of-pocket) described in Schedule 5, in the case of Ontario Hydro, or Schedule 6, in the case of Manitoba Hydro, incurred by the Other Party to the date of receipt by it of the Termination Notice (including costs which it will thereafter be obligated to pay under binding contracts). Within thirty days after receipt by it of the Certificate, the Terminating Party shall pay to the Other Party, which payment shall not be a penalty, the lesser of:

a. the aggregate amount of the costs shown by the Certificate, and

b. the amount set out in the table below.

Date Notice Given by Ontario Hydro	Amount Payable by Ontario Hydro to Manitoba Hydro (millions of dollars)
Between January 1 and March 31, 1991	$ 60
Between April 1 and June 30, 1991	$100
Between July 1 and September 30, 1991	$200
Between October 1 and December 31, 1991	$215
Between January 1 and March 31, 1992	$230
Between April 1 and June 30, 1992	$260
Between July 1 and September 30, 1992	$300
Between October 1 and December 31, 1992	$315
Between January 1 and March 31, 1993	$355
Between April 1 and June 30, 1993	$430
Between July 1 and September 30, 1993	$535
Between October 1 and December 31, 1993	$575
On or after January 1, 1994	$575

Date Notice Given by Manitoba Hydro	Amount Payable By Manitoba Hydro to Ontario Hydro (millions of dollars)
Between January 1 and March 31, 1991	$ 20
Between April 1 and June 30, 1991	$ 30
Between July 1 and September 30, 1991	$ 40
Between October 1 and December 31, 1991	$ 50
Between January 1 and March 31, 1992	$ 60
Between April 1 and June 30, 1992	$ 70
Between July 1 and September 30, 1992	$ 75
Between October 1 and December 31, 1992	$ 80
Between January 1 and March 31, 1993	$ 85
Between April 1 and June 30, 1993	$ 90
Between July 1 and September 30, 1993	$ 95
Between October 1 and December 31, 1993	$100
On or after January 1, 1994	$100

If a Termination Notice is given after December 31, 1993, the amount payable to the Other Party shall include interest in accordance with Section 9.06 from January 1, 1994 to and including the date the Other Party receives the Termination Notice. Subject to the provisions of Section 11.05, upon making the payment provided for in this Section, this Agreement and the Facilities Agreement shall thereupon terminate and be of no further force or effect whatsoever. If proceedings are commenced in accordance with Section 11.05, then on the resolution of the dispute, this Agreement and the Facilities Agreement shall terminate and have no further effect.

11.05 The Terminating Party or its representative, appointed by it for that purpose, upon notice and at its own expense, shall have access at all reasonable times to such of the books, records and reports of the Other Party as may reasonably be required in the sole opinion of the Terminating Party for the purposes of verifying any of the costs referred to in Section 11.04. Such access must be sought within a period of one year following the date of the Certificate. If there is any dispute as to the correctness or accuracy of the Certificate, the Terminating Party must commence proceedings in accordance with Article 12 within one year of the date of the Certificate.

11.06 Any payment not made when due shall bear interest in accordance with Section 9.06.

ARTICLE 12
DISPUTE RESOLUTION

12.01 If any dispute arises in respect of this Agreement which the Parties cannot resolve, the same may be resolved by submitting the dispute for arbitration if the Parties agree, or if the Parties fail to so agree, the dispute will be litigated in the Court of Queen's Bench for the Province of Manitoba.

12.02 If the Parties agree that a dispute is to be submitted for arbitration, then The Arbitration Act, RSM 1987, c. A120, as amended, shall apply and:

a. If the Parties are unable to agree upon a single arbitrator, the Parties shall each appoint one arbitrator and the two so appointed shall appoint a third. If the two arbitrators so appointed are unable to agree on the third arbitrator, the third arbitrator shall be appointed by the Chief Justice of the Court of Queen's Bench for the Province of Manitoba.

b. An award shall include interest where applicable.

c. An award shall allocate the fees and costs of the arbitrators but not of the Parties, and such allocation shall have regard to the nature and outcome of the dispute.

d. An award shall be final and binding upon the Parties.

e. Judgement upon an award may be entered in any court of competent jurisdiction.

12.03 Pending the final resolution of any dispute, the Parties agree to diligently proceed with the performance of all obligations, including the payment of all sums required by this Agreement. Interest shall accrue as specified in Section 9.06 on all overpayments and underpayments which occur pending resolution of the dispute. Interest provided for under this Agreement is payable after judgement at the same rate as before judgement.

ARTICLE 13
GENERAL

13.01 This Agreement is subject to Ontario Hydro obtaining the approval of the Lieutenant Governor in Council of Ontario and Manitoba Hydro obtaining the approval of the Lieutenant Governor in Council of Manitoba, on or before January 31, 1990, for the respective Party to enter into this Agreement.

13.02 This Agreement is not intended to and shall not create rights of any character whatsoever in favor of any person, corporation, association, or entity other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties.

13.03 This Agreement shall not create a relationship between the Parties of a joint venture or a partnership.

13.04 If either Party is unable to meet its obligations pursuant to this Agreement or the Facilities Agreement by reason of accident to its works, explosion, fire, flood, epidemic, war, riot, civil disturbance, wilful destruction of property, labour disturbance, vandalism, malicious acts, failure of equipment, Act of God or the public enemy, or other cause of like nature reasonably beyond the control of such Party, then such Party shall immediately notify the other of the cause for non-performance and shall be excused from the performance of such obligation for so long as the cause which makes it unable to perform continues, and such Party shall not be liable for any penalty, loss or damage caused by or resulting from such inability to perform; provided however, that this Section shall not be construed as permitting either Party to refuse to make any payment required of it under this Agreement, and each Party shall be prompt and diligent in removing the cause for non-performance and in performing its obligations hereunder once the cause for non-performance has been removed.

13.05 Neither Party shall be liable to the other with respect to any third party claim relating to this Agreement, whether based upon contract, tort (including without limitation negligence) or otherwise, for any indirect, incidental, or consequential damages.

13.06 No full or partial waiver at any time by a Party of any of its rights under this Agreement, including its rights with respect to breach by the other Party, shall be deemed a waiver with respect to any other right, including any right with respect to another or a subsequent breach by that other Party. No such waiver may be made or given except by Supplementary Agreement.

13.07 Neither Party shall assign all or part of its rights or delegate all or part of its obligations under this Agreement without the express written consent of the other Party, which consent shall not be unreasonably withheld; and the delegation or assignment by a Party of all or part of its rights or obligations under this Agreement shall not discharge such Party from its obligations under this Agreement, whether such delegation or assignment is consented to or not by the other Party, unless expressly provided by the written agreement of the other Party, which agreement to such discharge may be withheld. A delegation or assignment shall not be deemed to permit any further or other delegation or assignment.

13.08 This Agreement together with the Facilities Agreement represent the entire agreement between the Parties with respect to the subject matter hereof or thereof and supersede all prior oral and written proposals and communications pertaining hereto and thereto. There are no representations, conditions, warranties or agreements, express or implied, statutory or otherwise, with respect to or collateral to this Agreement and the Facilities Agreement other than contained herein or therein or expressly incorporated herein or therein. Unless otherwise specifically provided herein, this Agreement may be altered, modified or varied, in whole or in part, only by Supplementary Agreement.

13.09 Any notices, demands, or requests or other communications required or authorized by this Agreement shall be in writing addressed as follows:

General Counsel and Secretary
Ontario Hydro
700 University Avenue
Toronto, Ontario
M5G 1X6

if to Ontario Hydro;

and to

The President and Chief Executive Officer
Manitoba Hydro
820 Taylor Avenue
Winnipeg, Manitoba
R3C 2P4

if to Manitoba Hydro;

and shall be deemed accomplished upon actual receipt by the Party to whom addressed. The designation of the persons to be notified or the addresses of such persons may be changed at any time by similar notice.

13.10 This Agreement may be executed in two counterparts, each of which shall be an original and both of which shall constitute but one and the same instrument.

13.11 This Agreement shall be interpreted and enforced in accordance with the laws of the Province of Manitoba, and each of the Parties agrees to attorn to the jurisdiction of the courts of Manitoba.

13.12 Time shall be of the essence of this Agreement.

13.13 This Agreement shall inure to the benefit of and be binding upon the Parties hereto and their respective successors and permitted assigns.

13.14 Subject to Section 13.01, this Agreement becomes effective on the year and date first above written and shall continue in full force and effect until all obligations hereunder have been discharged.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their duly authorized officers as of the day and year first above written.

ACCEPTED AND AGREED TO BY:

THE MANITOBA HYDRO-ELECTRIC BOARD

A. Brian Ransom
Chairman of the Board

G.H. Beatty
President and
Chief Executive Officer

ONTARIO HYDRO

Robert C. Franklin

Robert C. Franklin
Chairman and President

SIGNED IN THE PRESENCE OF:

Gary Filmon

The Hon. Gary Filmon
Premier of the
Province of Manitoba

The Hon. David R. Peterson
Premier of the
Province of Ontario

SCHEDULE 1
MONTHLY CAPACITY RATE (A)

The Monthly Capacity Rate applicable to each of the twenty-two Contract Years shall be calculated at the beginning of each Contract Year as follows:

$$A_i = \frac{1}{12} \times \frac{(C_i)\ (D)\ (D + 1)^{40}}{(D + 1)^{40} - 1} \times F$$

where:

A_i is the Monthly Capacity Rate in dollars per kilowatt per Month for each block of Capacity, as defined below, in each Contract Year, where A_1 is for Block 1, A_2 is for block 2, etc.

C_i is the capital cost for each block of Capacity, as defined below, for each Contract Year, where C_1 is for block 1, C_2 is for block 2, etc.

D is weighted rate in decimal format calculated in the following manner:

In each year from 1993 to 2001 inclusive, a bond yield rate to the investor will be determined by Manitoba Hydro for twenty year public issues by Manitoba Hydro in Canada in Canadian dollars in accordance with the following borrowing schedule:

Calendar Year	Annual Borrowing Schedule (millions of dollars)
1993	150
1994	150
1995	300
1996	300
1997	500
1998	600
1999	600
2000	600
2001	300

Market indications of Manitoba Hydro bond yield rates for public debt issues in Canada to the investor shall be obtained by Manitoba Hydro in writing from three independent syndicate managers normally used by Manitoba Hydro for its public debt issues in Canada. Such managers shall be acceptable to Ontario Hydro; provided however, that such acceptance shall not be unreasonably withheld. Manitoba Hydro shall obtain the market indications for the nominal amounts stated above, on January 1, April 1, July 1 and October 1 of each year, and shall forward written copies of these indications to Ontario Hydro for information. The values thus provided for each quarter shall be averaged to obtain an annual average yield cost rate ("the annual rate") for each year from 1993 to 2001 inclusive.

The annual rates will then be weighted in accordance with the Annual Borrowing Schedule above to obtain a weighted average rate ("the weighted rate") each year as follows:

The weighted rate for any given year up to and including 2001 will be the annual rate (for the amount of borrowing in that year) weighted cumulatively with the annual rates for the previous years. For the first Contract Year, the weighted rate for the year 2000 will be used.

Except for the first Contract Year, billings for Capacity will use the weighted rate determined for 2001.

F is equal to 1.3 for the first five Contract Years, equal to 1.0 for Contract Years six to twelve, and equal to 0.75 for Contract Years thirteen to twenty-two. The multiplier of 1.3 for the first five Contract Years is in recognition of the multiplier of 0.75 for Contract Years thirteen to twenty-two.

The capital cost (CAP) applicable to October 31, 1988, for each block of Capacity is:

Block	Description	CAP October 31, 1988 ($/kW)
1	200 MW starting on November 1, 2000, ending on October 31, 2020	1727
2	200 MW starting on November 1, 2001, ending on October 31, 2021	1727
3	200 MW starting on November 1, 2002, ending on October 31, 2022	1727
4	200 MW starting on November 1, 2002, ending on October 31, 2022	1727
5	200 MW starting on November 1, 2003, ending on October 31, 2018	1603

CAP for each block will be adjusted to the beginning of the first Contract Year in which that block is made available to Ontario Hydro, using the Hydro Electric Generating Station Construction Price Index as published by Statistics Canada in Catalogue No. 62-007 as follows:

$$C_i = \frac{G}{G_B} \text{ x CAP \$/kW}$$

where:

G_B is the Hydro Electric Generating Station Construction Price Index for 1988. The preliminary index for 1988 is 353.1 (1971 = 100) but the final index for 1988 as published by Statistics Canada shall be utilized.

G is the Hydro Electric Generating Station Construction Price Index on the 1971 base for the year in which that block is first delivered.

If the final value of G is not known when required for billing, an estimated value will be used and an adjustment in billing will be made in accordance with Section 9.01 when the final value becomes known.

SCHEDULE 2
MONTHLY ENERGY RATE (B)

The energy rate applicable to July, 1988, is $22.10 per megawatt hour. This rate shall be adjusted to each Month using the Consumer Price Index (CPI) for Canada, published Monthly by Statistics Canada in Catalogue No. 62-001 for Canada; all items, not seasonally adjusted, as follows:

$$B = \frac{CPI}{CPI_B} \times 22.10 \times F$$

where:

B is the Monthly Energy Rate for a Month in dollars per megawatt hour.

CPI_B is the Consumer Price Index for July, 1988, which is 144.5 (1981 = 100).

CPI is the Consumer Price Index on the 1981 base for the Month three Months previous to the billing Month (eg. July is three Months previous to October).

F is equal to 1.3 for the first five Contract Years, equal to 1.0 for Contract Years six to twelve, and equal to 0.75 for Contract Years thirteen to twenty-two. The multiplier of 1.3 for the first five Contract Years is in recognition of the multiplier of 0.75 for Contract Years thirteen to twenty-two.

SCHEDULE 3
(NSP AGREEMENT ARTICLE 1)
SERVICE TO BE PROVIDED

1.01 Manitoba Hydro shall make 500 megawatts (MW) available to NSP at the points of delivery for the twelve Contract Years beginning May 1, 1993, and ending April 30, 2005, subject to the conditions of Sections 1.04 and 1.05 herein. Each Contract Year shall commence on May 1 and end on the following April 30.

1.02 The hourly delivery of energy shall be scheduled by NSP in accordance with guidelines set forth by the Coordinating Committee established in the Coordinating Agreement. The minimum hourly schedule shall not be less than 150 MW unless otherwise mutually agreed to by the Parties.

1.03 The points of delivery for transactions under this Agreement shall be the points of interconnection between The Manitoba Hydro-Electric Board and NSP on the International Boundary between Canada and the United States of America.

1.04 In the event of the unavailability of one or more generating units at Limestone or the unavailability of sufficient High Voltage Direct Current (HVDC) transmission from northern Manitoba to Winnipeg due to planned or unplanned maintenance or repairs, Manitoba Hydro may reduce the 500 MW delivery. The maximum allowable reduction shall be the greater of:

a. 50 MW per unavailable Limestone unit provided such units have been placed in commercial operation, or

b. The lesser of:

    i. The MW reduction from the rated load carrying capability of the HVDC facilities. The rated load carrying capability of the HVDC facilities shall be determined as necessary by the Coordinating Committee; or

    ii. The MW reduction required to enable Manitoba to meet its firm load commitments from its available firm resources. The definition of firm load and firm resources shall be established by the Coordinating Committee.

1.05 In the event of the unavailability of the 500 kV facility from Winnipeg to Minneapolis, the delivery will be limited to the schedule that NSP can arrange on the remaining interconnections between United States utilities and the Province of Manitoba.

1.06 Each Party shall at its own expense, operate and maintain its facilities to minimize as far as practicable reductions in this transaction.

SCHEDULE 4
CAPACITY UNAVAILABILITY AND CAPACITY ENTITLEMENT

Capacity Unavailability (U) is defined as:

$$U = \sum_{i=1}^{n} R_i t_i$$

where:

R_i	is the average reduction in kilowatts from the hourly schedule as a result of a curtailment pursuant to Section 6.03 or as a result of a curtailment due to an event within the Manitoba Hydro system as contemplated by Section 13.04. Any curtailment of duration less than five (5) consecutive minutes is not included in the calculation of Capacity Unavailability (U); however, if a curtailment is five (5) consecutive minutes or more in duration, then R_i is determined for the period of said curtailment.
t_i	is the duration of said curtailment in hours expressed in decimal format and is calculated from the time the curtailment started until the time the schedule is restored.
n	is the number of Capacity curtailments which occurred during the Month.

The Monthly Capacity Entitlement (Q) is defined as:

$$Q = S \times T$$

where:

S	is the contracted amount of the Capacity.
T	is the number of hours in the Month.

SCHEDULE 5

The costs contemplated by Section 11.04 shall include any and all costs incurred by Ontario Hydro to the date upon which the Termination Notice is received in connection with the New Interconnection Facilities as described in Section 2.01 of the Facilities Agreement, from the Manitoba - Ontario border to the Dryden Transformer Station (TS), the transmission line from Dryden TS to Mississagi TS, with intermediate switching and/or transformation at Lakehead TS and at a switching station near the mid-point between Lakehead TS and Mississagi TS, and the transmission line from Mississagi TS to Hanmer TS. The costs are generally those required to cover the approval processes, environmental studies for route and site selection and the preparation of required documentation, power system studies, financial studies, preliminary designs and engineering and the preparation of tender documents and bids for right-of-way clearing and for materials with a long lead time for delivery. Such costs shall be those costs recorded on the books of Ontario Hydro in accordance with its normal accounting principles, and without limiting the generality of the foregoing, shall include the costs associated with the following:

- Manitoba Hydro Interconnection - Environmental Studies and Route Selection;
- Manitoba Hydro Interconnection - 500 kV Transmission Line;
- Dryden TS - Termination of Ontario Hydro Interconnection;
- Dryden TS - 500 kV Switchyard with 500/230 kV Transformation and Associated Switchgear and Reactive Compensation Facilities;
- Environmental Studies and Route and Site Selection for 500 kV Transmission Lines from Dryden TS to Lakehead TS and from Lakehead TS to Mississagi TS;
- Dryden TS - Lakehead TS 500 kV Transmission Line;
- Lakehead TS - 500 kV Switchyard with 500/230 kV Transformation and Associated Switchgear and Reactive Compensation Facilities;
- Lakehead TS - Mid-point SS - Mississagi TS 500 kV Transmission Line;
- New Switching Station Near the Mid-point Between Lakehead TS and Mississagi TS;
- Mid-point SS - 500 kV Switchyard with Associated Switchgear and Reactive Compensation Facilities;
- Mississagi TS - 500 kV Switchyard with 500/230 kV Transformation and Associated Switchgear and Reactive Compensation Facilities;
- Mississagi TS - Hanmer TS 500 kV Transmission Line;
- Hanmer TS - Termination of 500 kV Transmission Line from Mississagi TS;

- Dryden TS - Manitoba Hydro Interconnection Telecontrol and Communication Facilities;
- Dryden TS - Hanmer TS Telecontrol and Communication Facilities;
- Kenora TS - Reactive Compensation Facilities;
- Overheads and other indirect costs associated with the above.

The above list of facilities assumes specific facilities and routes for transmission within the Province of Ontario. In the event that as a result of system studies, Ontario Hydro recommends alternative facilities or routes, or as a result of the approval process alternative facilities or routes are required, the above list of facilities may be modified by Ontario Hydro and notice of such modifications shall be given to Manitoba Hydro in accordance with Section 13.09; provided however, that the list of facilities shall not be modified after receipt of a Termination Notice. If any modifications are required to the facilities associated with the New Interconnection Facilities, such modification shall be made by Supplementary Agreement.

SCHEDULE 6

The costs contemplated by Section 11.04 shall include any and all costs incurred by Manitoba Hydro to the date upon which the Termination Notice is received in connection with the Conawapa Generating Station, the HVDC converter facilities, the transmission line from the Henday to Riel stations and the New Interconnection Facilities as described in Section 2.01 of the Facilities Agreement, from the Riel station to the Manitoba - Ontario border plus any and all costs incurred if Manitoba Hydro elects to halt such construction. The costs are generally those required to cover the approval processes, environmental studies for route and site selection and the preparation of required documentation, power system studies, financial studies, preliminary design and engineering and preparation of tender documents and bids for right-of-way clearing, and for materials with a long lead time for delivery and for construction of facilities. Such costs shall be those costs recorded on the books of Manitoba Hydro in accordance with its normal accounting principles, and without limiting the generality of the foregoing, shall include the costs associated with the following:

- Conawapa Generating Station;
- Conawapa Construction Power Station;
- Kettle Station - Termination of Conawapa Construction Power Transmission Line;
- Limestone - Conawapa Construction Power Station Transmission Line;
- Henday - Conawapa Switching Station 230 kV Transmission Line C61H and C62H;
- Conawapa Construction Power Station Termination of Backup;
- Henday Station - Conawapa Line Termination C61H and C62H;
- Conawapa Generation Station to Switching Station 230 kV Lines;
- Henday - Conawapa Switching Station 230 kV Lines;
- Conawapa Switching Station;
- Henday Station - Conawapa Termination Lines C63H and C64H;
- Conawapa Generating Station - Henday Communication Complex;
- Bipole 3 Transmission Line Environment Studies and Route Selection;
- Henday - Riel 500 kV DC Transmission Line;
- Riel Construction Power Station;
- Riel Station Bipole 3 - Stages 1 and 2;
- Henday Station Bipole 3 - Stages 1 and 2;
- Riel Station - Var Compensation;
- Riel - Bipole 3 Electrode Line and Station;

- Henday - Bipole 3 Electrode Line;
- Bipole 3 Telecontrol Facilities;
- Dorsey - Riel 500 kV Transmission Line;
- Dorsey Station - HVDC Termination;
- Riel Station - HVDC Termination;
- Dorsey - Riel Telecontrol Complex;
- Dorsey 500 kV Station Reactor Salvage and Protection Replacement;
- Riel 500 - 230 kV AC Switchyard;
- Dorsey - Riel - Forbes Telecontrol Complex;
- Ontario Hydro Interconnection - Environmental Studies and Route Selection;
- Ontario Hydro Interconnection - 500 kV Transmission Line;
- Riel Station - Termination of Ontario Hydro Interconnection and Phase Shifting Transformers;
- Riel Station - Phase Shifting Transformers;
- Riel Station - Ontario Hydro Interconnection Telecontrol and Communication Complex;
- Whiteshell Station Modifications for Ontario Hydro Interconnection;
- Overheads and other indirect costs associated with the above.

The above list of facilities assumes specific facilities and routes for transmission within the Province of Manitoba. In the event that as a result of system studies, Manitoba Hydro recommends alternative facilities or routes, or as a result of the approval process alternative facilities or routes are required, the above list of facilities may be modified by Manitoba Hydro and notice of such modifications shall be given to Ontario Hydro in accordance with Section 13.09; provided however, that the list of facilities shall not be modified after receipt of a Termination Notice. If any modifications are required to the facilities associated with the New Interconnection Facilities, such modification shall be made by Supplementary Agreement.

FACILITIES AGREEMENT

MANITOBA–ONTARIO INTERCONNECTION

between

THE MANITOBA HYDRO-ELECTRIC BOARD

and

ONTARIO HYDRO

DECEMBER 7,1989

MANITOBA-ONTARIO FACILITIES AGREEMENT

THIS MANITOBA-ONTARIO FACILITIES AGREEMENT (the "Facilities Agreement") is made and entered into this 7th day of December, 1989 by and between Ontario Hydro, an Ontario Statutory Corporation, and The Manitoba Hydro-Electric Board ("Manitoba Hydro") a Manitoba Crown Corporation, (each of the foregoing entities being sometimes referred to individually as "Party" and both being sometimes collectively referred to as "Parties").

WITNESSETH:

0.01 WHEREAS, the systems of Manitoba Hydro and Ontario Hydro are interconnected by transmission lines and are operating in synchronism;

0.02 WHEREAS, Manitoba Hydro and Ontario Hydro intend to construct, operate and maintain the transmission facilities referred to in this Facilities Agreement;

0.03 WHEREAS, when Manitoba Hydro and Ontario Hydro execute and deliver this Facilities Agreement, they have also agreed to concurrently execute and deliver the Manitoba-Ontario Power Transaction Agreement (the "Transaction Agreement").

NOW THEREFORE, the Parties agree as follows:

ARTICLE 1
DEFINITIONS

1.01 Unless otherwise specified in this Facilities Agreement, all definitions and references to and use of terms and their abbreviations, and related factors and associated calculation methods shall have the meanings which are set out in the Transaction Agreement.

1.02 Criteria - shall mean the planning criteria described in Schedule A.

1.03 Design Transfer Capability - shall mean the planned ability to transmit power.

1.04 New Interconnection Facilities - shall mean the facilities described in Section 2.01 of this Facilities Agreement.

ARTICLE 2
NEW INTERCONNECTION FACILITIES

2.01 The New Interconnection Facilities shall consist of a single circuit overhead 500 kV, 60 Hz alternating current transmission line between a terminal point at a station near Winnipeg, in the Province of Manitoba, and a terminal point at a station in the vicinity of Dryden, in the Province of Ontario, and portions of the stations located at the terminal points, including any equipment associated with reactive compensation, communications, protection, metering, monitoring and control and other associated equipment.

2.02 The New Interconnection Facilities shall only include those facilities that are generally described in Section 2.01, unless set forth in a Supplementary Agreement.

2.03 Manitoba Hydro shall design, construct, place in service, own and maintain that portion of the New Interconnection Facilities located in the Province of Manitoba, or cause any or all of the same to be done. Ontario Hydro shall design, construct, place in service, own and maintain that portion of the New Interconnection Facilities located in the Province of Ontario, or cause any or all of the same to be done.

2.04 Manitoba Hydro and Ontario Hydro will coordinate their respective environmental assessment studies, pertaining to the selection and location of routes for that portion of the New Interconnection Facilities located in each province, such that a recommended Manitoba-Ontario interprovincial boundary crossing point (the "Crossing Point") is established. If a mutually acceptable Crossing Point is not identified by December 31, 1990, the Parties shall jointly propose that the recommended Crossing Point be located adjacent to and north of the point where the existing 230 kV interconnections cross the Manitoba-Ontario interprovincial boundary.

ARTICLE 3
OTHER FACILITIES

3.01 Manitoba Hydro shall, in accordance with the Criteria, plan, design, construct, place in service and maintain that portion of its facilities which in its sole discretion is required for the delivery of no less than 1 500 MW to the Point of Interconnection.

3.02 Ontario Hydro shall, in accordance with the Criteria, plan, design, construct, place in service and maintain that portion of its facilities which, in its sole discretion, is required to receive no less than 1 500 MW from the Point of Interconnection.

3.03 Subject to Sections 3.01 and 3.02, each Party may plan, design, construct, operate and maintain its existing and future facilities in such manner as it, in its sole discretion, deems appropriate.

ARTICLE 4
SYSTEM STUDIES

4.01 The Parties agree to carry out joint power system studies.

4.02 The design of the New Interconnection Facilities and the other facilities described in Sections 3.01 and 3.02 shall be demonstrated in studies to be in accordance with the Criteria, and to be capable of meeting a Design Transfer Capability of not less than 1 500 MW. The Design Transfer Capability of not less than 1 500 MW shall include the transfer capability of the existing 230 kV interconnection facilities between Manitoba Hydro and Ontario Hydro.

4.03 The Parties shall coordinate the overall design of the New Interconnection Facilities by cooperating in the exchange of relevant data and information, and by providing the opportunity for each Party to review the design and development work of the other in sufficient detail and with adequate allowance for time prior to the commitment of any construction.

4.04 The Parties agree to cooperate in the design of the facilities contemplated by Sections 3.01 and 3.02, by providing all relevant data, information and study results in sufficient detail and with adequate allowance for time prior to the commitment of any construction.

4.05 Each of the Parties shall proceed independently of the other with respect to the engineering, construction and financing of the portion of the New Interconnection Facilities for which it is responsible.

ARTICLE 5
IN-SERVICE DATE

5.01 Each Party shall ensure that its portion of the New Interconnection Facilities and the facilities described in Sections 3.01 and 3.02 for which it is responsible are ready for service on or before November 1, 2000. By Supplementary

Agreement, the Parties may agree to stage the in-service dates starting November 1, 2000, to coincide with the staging of the System Participation Power as described in Section 2.01 of the Transaction Agreement, provided that the New Interconnection Facilities and the facilities described in Sections 3.01 and 3.02 are completed no later than November 1, 2003.

ARTICLE 6
COST OF FACILITIES

6.01 Manitoba Hydro shall pay or cause to be paid all costs associated with the New Interconnection Facilities located in the Province of Manitoba and with the other facilities described in Section 3.01, and Ontario Hydro shall not have any obligation to pay or contribute to such costs.

6.02 Ontario Hydro shall pay or cause to be paid all costs associated with the New Interconnection Facilities located in the Province of Ontario and with the other facilities described in Section 3.02, and Manitoba Hydro shall not have any obligation to pay or contribute to such costs.

ARTICLE 7
FACILITIES COMMITTEE

7.01 A committee, known as the "Facilities Committee" is hereby established and shall have the responsibility and authority to coordinate the system studies, environmental assessment, including the recommended Crossing Point, planning, and design, and to monitor the construction and testing of the New Interconnection Facilities. In carrying out the responsibilities and authorities provided herein, the Facilities Committee shall undertake discussions and joint studies in order to select the most favourable scheme, which may include, for the New Interconnection Facilities, a scheme other than that described in Section 2.01, provided however, that Section 2.01 shall only be altered, amended or revised pursuant to a Supplementary Agreement.

7.02 The Facilities Committee shall consist of two members, one member appointed by and representing Manitoba Hydro and one member appointed by and representing Ontario Hydro. Members shall be named, selected and changed by appropriate notice in accordance with Section 13.09 of the Transaction Agreement, mutatis mutandis. All decisions of the Facilities Committee shall be unanimous.

7.03 The Facilities Committee shall meet at the request of either member, and prior to the in-service date of the facilities described in Section 5.01, it shall meet at least semi-annually. Written minutes shall be kept of all meetings and copies of such shall be mailed to each member within ten working days after each meeting. Failure to object to the minutes within thirty days after receipt shall be deemed to be approval thereof.

ARTICLE 8
JOINT STUDY COSTS AND EXPENSES

8.01 With the prior written consent of both Parties, certain joint study costs and expenses relating to the activities covered by this Facilities Agreement may be shared.

8.02 Shared costs and expenses as defined in Section 8.01 are to be invoiced in accordance with the procedure to be established by the Facilities Committee.

ARTICLE 9
GENERAL

9.01 Except as otherwise provided herein, the provisions of Articles 11, 12 and 13 of the Transaction Agreement and the Sections of the Transaction Agreement referred to in such Articles shall apply to this Facilities Agreement, with the exception of Secton 13.01, mutatis mutandis, provided that no additional payment shall be required to be made pursuant to Section 11.04 of the Transaction Agreement under this Facilities Agreement.

9.02 This Facilities Agreement shall become effective on the year and date first above written and shall continue in full force and effect as long as the Transaction Agreement continues in full force and effect.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their duly authorized officers as of the day and year first above written.

ACCEPTED AND AGREED TO BY:

THE MANITOBA HYDRO-ELECTRIC BOARD

A. Brian Ransom
Chairman of the Board

G.H. Beatty
President and
Chief Executive Officer

ONTARIO HYDRO

Robert C Franklin

Robert C. Franklin
Chairman and President

SIGNED IN THE PRESENCE OF:

Gary Filmon

The Hon. Gary Filmon
Premier of the
Province of Manitoba

The Hon. David R. Peterson
Premier of the
Province of Ontario